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Smart Inverter Operationalization (SIO) Working Group Report

Business Cases and Use Cases

February 1, 2024

Preface

The Smart Inverter Operationalization Working Group (SIOWG) was formed under Track 3 Phase 1 within the "*Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*", Rulemaking 21-06-017.

SIOWG process. The SIOWG was facilitated by Xanthus Consulting International in partnership with Verdant Associates, LLC. on behalf of the CPUC. Approximately 110 interested individuals from 51 organizations representing distributed energy resource (DER) manufacturers and implementers, electric vehicle manufacturers, research institutes, advocacy groups, the three main electric investor-owned utilities (termed distribution system operators (DSOs)), other electric utilities, university staff, CPUC staff, CEC staff, CAISO staff, and consultants. The group met bi-weekly for nearly 2 years, starting on January 25, 2022. SIOWG participants were asked to prioritize and review the operationalization of the smart inverter use cases identified in the Rule 21 Working Group Four Report[1] plus other potential use cases.

The SIOWG determined that the discussion of operational flexibility warranted bi-weekly meetings, first to understand the issues, secondly to resolve what actions might be taken by the CPUC in the near-term to prepare for the High DER Future, and eventually to develop the Working Group Report (this document). The following actions were taken:

- Bi-weekly meetings of 1.5 hours each, starting January 25, 2022
- Material for each meeting, including agendas and updated documents, prepared by Xanthus
- Most meetings captured in videos
- Open discussions and chat inputs by participants during meetings
- Presentations from participants, including the DSOs under CPUC jurisdiction
- Assignment of action items to specific participants
- Comments and tracked changes on documents uploaded to the Verdant SharePoint site
- Development of draft documents between meetings, including a spreadsheet for prioritizing the use cases, draft Business Cases, draft Use Cases, and a draft Working Group Report combining the Business Cases and Use Cases.
- Review of draft SIO Working Group Report by CPUC staff for accuracy and readability
- Update of draft SIO Working Group Report based on CPUC staff comments
- Delivery of the final SIO Working Group Report to the CPUC High DER Future [21-06-017] Service List to be followed by a ruling at a later date requesting on the record party comments

The following actions are planned after the finalization of the SIO Working Group Report:

- Development of draft SIO Staff Proposal reflecting formal comments on the Final SIO Working Group Report, staff research and analysis, and consultant content contributions
- Review of draft SIO Staff Proposal by the Energy Division Management and CPUC Decision Makers
- Delivery of ED SIO Staff Proposal to OIR parties for formal comments and workshop.
- CPUC Decision on SIO Staff Proposal and SIOWG Reports.

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[1] *Rule 21 Working Group Four Final Report, August 12, 2020, California Public Utilities Commission Interconnection Rulemaking (R.17-07-007), at 79. Available at https://gridworks.org/wp-content/uploads/2020/08/R21-WG4-Final-Report.pdf. See also D.21-06-002 at 68. Preliminary list of use cases are listed in Annex F and Annex G to the Rule 21 Working Group Three Final Report, June 14, 2019, California Public Utilities Commission Interconnection Rulemaking (R.17-07-007). Available at: https://gridworks.org/wpcontent/uploads/2021/02/R1707007-Working-Group-Three-Final-Report.pdf.*

<u>CPUC Tariffs and Proceedings Potentially Affected</u>. The following CPUC tariffs may be affected by the recommended actions in this report: Rule 21, Rule 2, Rule 15, Rule 16, Rule 29, and Rule 45. The following proceedings may also be affected: Interconnection Rulemaking (R.17-07-007), Demand Flexibility Rulemaking (R.22-07-005), Microgrid Proceeding (R.19-09-009), DRIVE Rulemaking (18-12-006), and the new Energization OIR planned in response to SB 410[2]. Regulations and tariffs required for managing both export and import flexible limits could be addressed in one new OIR or, if need be, two well-coordinated OIRs.

<u>Report Contents</u>. This report describes the working group process and outcomes. Within this report,

- Section 1 covers the Scope of the SIOWG
- Section 2 includes terms and definitions
- Section 3 provides an overview of the entire SIOWG results. Note that sections 1-3 are intended to provide a less technical overview, whereas sections 4-10 present more detail for each business and use case
- Sections 4-10 present the business and use cases in detail
- Section 11 provides several potential actions by the CPUC and includes:
    - The likely steps needed to operationalize the business and use cases
    - What proceedings might need to consider each business and use case
    - What electric rules might be affected by the use cases
    - Technology update requirements and their estimated timelines.

[2] *California Senate Bill 410, Becker, Powering Up Californians Act, Approved by Governor October 07, 2023: 1) It is the policy of the state to reach carbon neutrality no later than 2045 and to maintain net negative emissions of greenhouse gases after 2045. To meet these goals and federal, state, regional, and local air quality and decarbonization standards, plans, and regulations, projections from the commission and the Energy Commission show the need for a large increase in both the quantity of electricity used and the functions for which electricity will be used. (2) To meet these decarbonization goals and federal, state, regional, and local air quality and decarbonization standards, plans, and regulations, the state's electrical distribution systems must be substantially upgraded, new customers must promptly connect to the electrical distribution system, and existing customers must have their service level promptly upgraded.*

Executive Summary

SIOWG Scope and Process. The Smart Inverter Operationalization Working Group (SIOWG) was formed under Track 3 Phase 1 within the "*Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*", Rulemaking 21-06-017. The SIOWG focused on answering the first two Track 3 Phase 1 questions in the High DER Amended Scoping Ruling[3]:

1. *Which smart inverter[4] operationalization use cases should be prioritized and implemented to leverage the capabilities of smart inverters to provide value to grid operators and ratepayers?*
2. *What technology roadmaps or other relevant Commission directives related to DERMS and to smart inverter operationalization should be adopted to ensure the utilities are able to implement the Working Group's recommendations?[5]*

This SIOWG report describes the work and product of the SIOWG participants. A companion report from the SIO Cybersecurity Subgroup (SIO-CS) (to be published shortly) focused on the third question in Track 3 Phase 13.3. of the Amended Scoping Ruling:

3. *What existing cybersecurity standards should be applied for smart inverter operationalization and DERMS to ensure communications between the equipment and management systems are secure (e.g., Institute of Electrical and Electronics Engineers (IEEE) 1547.3)?*

These two SIO working group reports will be followed by a California Public Utilities Commission (CPUC) Staff Proposal that will focus on identifying recommended CPUC actions in response to the two SIOWG reports. The Staff Proposal will be developed based on the working group reports, as well as party comments, staff research and analysis, and consultant input.

Key Findings. The SIOWG focused on operational flexibility as the highest priority, namely the ability of the DSOs in the high DER future to flexibly optimize the use of existing capacity, allowing more rapid connections of DER and loads, while still maintaining grid safety and reliability. The key findings included:

- Firm and Non-Firm Export Limits of power are necessary for operational flexibility and optimal use of existing capacity as more DER are interconnected to the grid.
- Firm and Non-Firm Import Limits of power are necessary for operational flexibility and optimal use of existing capacity as more Electric Vehicles and other loads need rapid connections, while waiting for grid upgrades.
- Export and Import Limits must be managed by a Power System Controller (PCS) and tested at the Point of Common Coupling (PCC) (i.e., site of DSO revenue meters) rather than at individual device connection points.
- Scheduling of Export and Import Limits will need to be updated via communications and to become more granular, namely by week, by day of week, by day, by hour of day.
- Regulations and tariffs for Export and Import Limits should be either handled in one proceeding or in two well-coordinated proceedings.

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[3] Assigned Commissioner's Amended Scoping Memo and Ruling in Rulemaking 21-06-017, COM/DH7/smt 8/11/2023, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M516/K786/516786462.PDF

[4] The term "smart inverter" was originally used for photovoltaic systems and eventually energy storage systems whose inverters had the ability to manage active power and reactive power in response to signals from their controllers. Over time, many other types of generating systems and load control systems were found capable of providing similar responses if managed by power control systems. Therefore, systems using smart inverters became a subset of a more general category of energy systems, termed "distributed energy resources" or DER. It was thus agreed that any type of DER system that can provide the operational flexibility described in the use cases could be included.

[5] *Note that many of the detailed answers to question 2 will be addressed in the staff proposal and are not fully addressed in this report.*

<u>Business Cases and Use Cases</u>. For this report, both business cases and use cases were developed, defined as:

- **Business Case.** Description of business objectives or purposes that could be provided through regulations, procedures, and/or technology. Typically, business cases stay at a high level to focus on ***what*** or ***why*** a process is needed, but ***not how*** that process might be implemented. Multiple, more technical **Use Cases** specify the process to support each business case.
- **Use Case**. Description of technical methods for supporting Business Cases. Use Cases may also be high-level or may be detailed but are focused on ***how*** the process might be implemented.

The SIOWG established seven (7) Business Cases (A-G) to identify the criteria for evaluating the various use cases. Based on these criteria, the SIOWG participants rated which use cases should be deemed high priority in the near-term and in the longer term, and which were deemed lower priority. The prioritization process was primarily based on the technical readiness and functional importance of the proposed solutions to the DSOs for maintaining grid safety and reliability, while some prioritizations were based on possible benefits to ratepayers and, indirectly, to society, such as the more effective use of available grid capacity to minimize or defer grid upgrades and to make more efficient use of renewable DER systems. Although such value judgments on priority are subjective and were discussed in detail during the meetings, ultimately there was consensus agreeing to the results described in the use cases. Additional metrics may need to be developed to prioritize the implementation timelines.

Often multiple use cases can help meet the same business case, and conversely, the same use case can help meet multiple business cases. Therefore, both Business Cases and their associated Use Cases were necessary to describe the assessments of the SIOWG. A case in point are the three (3) Business Cases A, B, and C that have different goals, but that rely on four (4) very similar Use Cases to achieve those different goals:

- **Business Case A** (DER Interconnection Agreement/Limited Load Profiles) proposes a high DER future supported by flexible DER **Interconnection Agreements** with a combination of firm export limits plus non-firm export capacity. Flexible **Limited Load Profiles** consist of a combination of firm import limits plus non-firm import capacity. DSOs would authorize the use of this non-firm capacity for export or import when available capacity on the relevant circuits would permit this use. Contractual flexibility to dynamically manage export and import limits is central to this business case and to Business Cases B and C. This flexibility in limits will help the DSOs meet the requirements of SB 410, specifically "*new customers must promptly [be allowed to] connect to the electrical distribution system, and existing customers must have their service level promptly upgraded*", since export and/or import limits can be imposed while the grid is still being upgraded, while retaining the contractual flexibility to modify or remove the limits once grid upgrades are completed.
- **Business Case B** (Abnormal Conditions) addresses the **abnormal grid situations** in which the DSOs can **mandate** export and/or import limits even if these are lower than the firm limits. The DSOs could also provide information to DER operators before or during transitions to abnormal grid configurations so that DER operators can better prepare. Abnormal conditions include real-time emergencies, planned grid maintenance operations, and forecasted system emergencies.
- **Business Case C** (Distribution Services during Normal Conditions) foresees the situation in which DER services may support DSOs, as well as can benefit communities, CAISO, DER owners / aggregators, ratepayers, and society **under normal grid conditions** in the high DER future. The focus is to optimize the use of firm and non-firm export and import capacity to support these distribution services.

The key Use Cases directly associated with Business Cases A, B, and C are:

- Use Case 1: Scheduling of Firm Export Limits and Non-Firm Export Capacity
- Use Case 2: Commanded Firm Export Limits and Non-Firm Export Capacity
- Use Case 3: Generation Export Minimum Requirement
- Use Case 4: Operational Flexibility in Import Limits and Non-Firm Import Capacity

<u>Priority of Use Cases</u>. The highest priority Use Case with the potential for near-term implementation is **Use Case 1, scheduling of export limits.** This is due to the current work in proceeding R.17-07-007 on Limited Generation Profiles (LGP)[6] which will allow generators and energy storage the option to have schedules of export limits. Use Case 1 identifies how those LGP export limits could be made more flexible and could thus vary by hour, day of the week, month, or season.

Use Case 2, commands of export limits, is the next highest priority based on time to implement. **Use Case 3, minimum export requirement,** may need additional time to implement than the first two since it is a different type of export requirement. **Use Case 4, import limiting**, will clearly require more regulatory proceedings and appropriate tariffs for applying limits to loads, and therefore may take significantly longer to implement.

<u>Additional Business Cases.</u> In addition to Business Cases A, B, and C, the SIOWG identified three other priority Business Cases that focus on EVs, community microgrids, and ISO services:

- Business Case E: Operational Flexibility for Electric Vehicles Providing Distribution Services, including specific Use Cases focused on electric vehicles
- Business Case F: Operational Flexibility in Community Microgrids
- Business Case G: Operational Flexibility for DER Providing ISO Grid Services

The SIOWG identified one Business Case that was not deemed high a priority:

- Business Case D: Operational Flexibility through Voltage Support by DER was not deemed as high priority since the DSOs stated that their equipment can manage grid voltages.

<u>Operational Flexibility</u>. All of the high priority use cases primarily focused on "**operational flexibility**", namely the ability of a power system to respond reliably and safely to changes in electricity demand and generation. From the perspective of the Rule 21 Tariff, operational flexibility involves the ability of DER facilities to respect grid constraints when and where necessary for grid reliability and safety, but to be permitted to make use of varying grid capacity for providing services to the DSOs, to CAISO, to ratepayers, and to the DER owners. Although many types of operational flexibility were explored and many were deemed high priority, some key findings stand out:

- The grid's capacity to permit the export of power from facilities varies greatly over time, including by hour, day of the week, month, season, and year. Therefore, the SIOWG identified that operational flexibility would necessitate the DSOs to authorize the use of any unused but available capacity at different times for additional export by DER facilities for the benefit of the grid and ratepayers, so long as this did not compromise grid safety and reliability. This resulted in the concept of Interconnection Agreements between DSOs and DER facilities having "firm export limits" (as currently included in Interconnection Agreements), but also optional "non-firm export capacity" that could be authorized by the DSO if their power flow studies showed that more capacity existed that the DER facility could utilize to export additional power.
- The grid's capacity is also affected by loads (importing power to customers), particularly due to the rapidly increasing electrification. The DSOs have an "obligation to serve" by providing grid capacity for all customer loads. But loads can also vary over time and can be managed if incentives (e.g., tariffs, demand response, etc.) are applied to shift the timing of these loads. So, the same issue of operational flexibility applies to importing power. Therefore, the SIOWG identified a concept that "Limited Load Profiles"

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[6] *The Large IOUs filed a Joint Advice Letter— PG&E Advice Letter 6816-E, SCE Advice Letter 4941-E, and SDG&E Advice Letter 4138-E –on January 9, 2023, and a Joint Supplemental Advice Letter— PG&E Advice Letter 6816-E-A, SCE Advice Letter 4941-E-A, and SDG&E Advice Letter 4138-E-A–on January 23, 2023, to meet the requirements of Resolution E-5211. The Large IOUs filed a Joint Advice Letter—PG&E Advice Letter 6929-E, SCE Advice Letter 5025-E, and SDG&E Advice Later 4215-E—on May 1, 2023, to meet the requirements of Resolution E-5230. The Advice Letters are under review by Energy Division and will be subject of an upcoming resolution Quarter 4 of 2023.*

(informal term for contracts related to loads) would have "**firm import limits**", plus optional "**non-firm import capacity**".

Challenges. Achieving this greater operational flexibility presents some key challenges. These include the following technology developments and their estimated timeframes after the CPUC decisions are made on the recommendations of the use cases:

- The DSOs will need to ensure that their power management systems (Advanced Distribution Management System (ADMS) and DER Management Systems (DERMS, and others) can assess the actual capacity available on different circuits and are able to send commands, verify performance, and take corrective actions for not performing as commanded, requiring an estimated 2-5 years of DSO development. Scheduling of firm and non-firm export limits would be implemented first, with the other Use Cases following later
- The DSOs and the DER facilities (and their aggregators) will need to support the communications needed to exchange the operational flexibility information and permissions, including the use of schedules for authorizing non-firm export and/or import capacity, requiring phased development, testing, and deployment over an estimated 2 to 10 years with pilot projects and a focus on the larger DER facilities.
- Testing and certification requirements will need to be developed and/or updated to reflect the new scheduling and command requirements supported by Power Control Systems rather than only type-testing of individual DER units. The estimated timeframe is 1-2 years.
- The CPUC will need to determine the regulations and tariffs necessary to fairly and effectively support this operational flexibility.

Consensus/Non-Consensus. All SIOWG participants who entered consensus/non-consensus statements, agreed with these concepts albeit with some qualifications related to the challenges listed above, including SCE, PG&E, SDG&E, CAISO, Enphase, IREC, and 350BA.

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1 Scope of the Smart Inverter Operationalization Working Group (SIOWG)

1.1 Establishment of the SIOWG

The SIOWG was formed as Track 3 within the "*Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*", Rulemaking 21-06-017[7]. The SIOWG consists of approximately 110 interested individuals from 51 organizations representing the three main electric investor-owned utilities (termed distribution system operators (DSOs), CPUC staff, CEC staff, CAISO staff, other electric utilities, distributed energy resource (DER) manufacturers and implementers, electric vehicle manufacturers, research institutes, advocacy groups, university staff, and consultants.

The SIOWG was facilitated by Xanthus Consulting International under contract to Verdant and the CPUC. The group met bi-weekly for 2 years, starting on January 25, 2022, with the mission of develop recommendations to the CPUC on enhancing the utilization of the existing Rule 21 tariff[8] smart inverters functions. The goals of the SIOWG included improving the reliability, safety, and capacity of the distribution system to meet ratepayer needs, while helping to defer grid upgrade costs borne by DER owners and by the DSOs in the near-term and the longer-term.

The Rule 21 Tariff Working Group Four Report[9] identified a number of issues, one of which (*Issue F: What Interconnection rules should the Commission adopt to account for the ability of Distributed Energy Resource Management Systems (DERMS) and aggregator commands to address operational flexibility need?*) recommended that a Smart Inverter Operationalization Working Group (SIOWG) should be formed to address operational flexibility. A scoping memo was developed to define the purpose of the SIOWG, shown in Section 1.2.

This document is the report from the Smart Inverter Operationalization Working Group (SIOWG) that describes the work and results from the SIOWG participants. A Staff Proposal will address actual recommendations to the CPUC.

1.2 Scoping Statements as Related to the SIOWG

The SIOWG scoping statement in Rulemaking 21-06-017 states:

"*The Commission launched R.21-06-017 not only to address the continuing actions from R.14-08-013 and R.14-10-003,2 but also to study the impacts of high penetrations of DERs on the grid and identify strategies for planning and forecasting distribution system investments necessary to support a large number of DERs on the grid in the future, which we now refer to as a High DER Grid future*."

… "Track 3, Phase 1 of the CPUC's High DER Future proceeding identified the scope of the Smart Inverter Operationalization Working Group as follows:

1. *Which smart inverter operationalization use cases should be prioritized and implemented to leverage the capabilities of smart inverters to provide value to grid operators and ratepayers? Parties should consider, but are not limited to, the smart inverter operationalization use cases identified in the Rule 21 Tariff Working Group Four Report [see Annex A,* History of Smart Inverter Functions*].*

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[7] *CPUC Ruling 21-06-017,* Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future, Assigned Commissioner's Scoping Memo and Ruling *(COM/DH7/nd3 11/15/2021), 11/15/2021*

[8] *CPUC Rule 21 Electric Interconnection Tariff that describes the interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system. https://www.cpuc.ca.gov/rule21/#:~:text=Rule%2021%20governs%20CPUC%2Djurisdictional,cost%20to%20the%20host%20utility.*

[9] *CPUC Interconnection Rulemaking (R.17-07-007), Working Group Four Final Report, August 12, 2020*

a. *What technical, regulatory, functional, and operational guidelines or requirements for high priority smart inverter operationalization use cases should the Smart Inverter Operationalization Working Group develop for Commission consideration?*

b. *For each priority use case, what are the specific communications and Distributed Energy Resources Management System (DERMS) requirements (e.g., real-time or near-real-time communications, DERMS power flow assessment capabilities)?*

c. *For priority use cases what are the policies, rules, and guidance on how Utilities should schedule or dispatch aggregators and/or DERs and how aggregators/DERs must respond to utility signals?*

2. *What technology roadmaps or other relevant Commission directives related to DERMS and to smart inverter operationalization should be adopted to ensure the utilities are able to implement the Working Group's recommendations?*

3. *What existing cybersecurity standards should be applied for smart inverter operationalization and DERMS to ensure communications between the equipment and management systems are secure (e.g., Institute of Electrical and Electronics Engineers (IEEE) 1547.3)?"*

… "Second, this scoping memo establishes the Smart Inverter Operationalization Working Group (Working Group). The Working Group should consider, but not be limited to, the smart inverter operationalization use cases identified in the Rule 21 Tariff [R.17-07-007] Working Group Four Report. Other smart inverter operationalization use cases the Working Group should consider include but are not limited to:

- *Operational flexibility[10] for Phase 1 functions (e.g., activation/deactivation and alternative settings for Anti-Islanding, Voltage Ride-Through, Frequency Ride-Through, Volt-Var, Fixed Power Factor, Frequency-Watt, Volt-Watt, Ramp Rates, and Soft-Start)[11];*
- *Operational flexibility for Phase 3 functions (e.g., activation/deactivation and alternative settings for Limit Active Power, Set Active Power, Schedule Limit Active Power);*
- *Operational flexibility by adding IEEE Std 1547 functions (e.g., activation/deactivation and settings for Constant Reactive Power and Watt-Var);*
- *Operational safety and reliability (e.g., activation/deactivation and settings for Monitor Key Data, Fast Frequency Response, Operational Reserve, Peak Power Limiting, Unintentional Islanding, and Black Start);*
- *Ancillary Services provided to Utility by distributed energy resources owner (e.g., activation/ deactivation and settings for automatic generation control, Artificial Inertia, Active Power Smoothing, Load Following, Generation Following, Power Factor Limiting, and Scheduling of Functions); and*
- *Other grid benefits provided by distributed energy resource (e.g., activation/deactivation and settings for Coordinated Charge/Discharge, Intentional Islanding, Microgrid Management, Backup Power, and Energy Arbitrage)."*

The SIO Cybersecurity Subgroup is developing a separate Working Group Report that will be published soon.

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[10] Operational flexibility refers to the ability of a power system to respond to changes in electricity demand and generation. For example, the ability to: transfer loads between distribution circuits, disconnect/reconnect distributed generation to the grid depending on available grid capacity, and respond to and mitigate voltage or frequency anomalies. Flexibility is particularly important for the integration of high levels of solar and wind, which have variable and uncertain power output. For this reason, batteries or other energy storage are important with respect to integrating solar and wind generation. Any distributed energy resources, including electric vehicles, can support this need for power system flexibility if the required functions and standards are in place and enabled.

[11] Order Instituting Rulemaking on the Commission's Own Motion to improve distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources. Rulemaking 11-09-011, "Interim Decision Adopting Revisions to Electric Tariff Rule 21 Tariff for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company To Require "Smart" Inverters", 11/13/2014

1.3 Operational Flexibility in the High DER Future

As identified in the SIOWG scoping memo, **operational flexibility** is a key requirement in the High DER Future. This is a significant change from the current fixed interconnection requirements. Operational flexibility will provide distributed energy resource (DER) systems with a greater ability to support distribution grid safety, reliability, and congestion management, and will permit Distribution System Operators (DSOs) to manage the import of power required by customer loads more effectively.

DER power exports. At the present time, the Interconnection Agreement contracts between DSOs and DER vendors are generally[12] fixed in what type-testing requirements the DER units must meet (i.e., Rule 21), the Integration Capacity Analysis (ICA) assessments that limit the size of DER generators, and the inability to modify any values without returning to the DSO's interconnection queue for a new Interconnection Agreement. These fixed contracts are justified because the DSOs do not currently have the assessment capacity to know actual grid conditions, nor the communications capability to permit modifications to DER constraints when grid conditions might make relaxation of these constraints possible. Although Rule 21 Tariff (SIWG Phase 2 communication requirements[13]) identifies the requirement to have the *capability* to implement communications between the DSO and the DER site, the reality is that two-way communications have not yet been implemented by the DSOs (except for one-way telemetry for DER units greater than 1 MW. Facilities exporting more than 1 MW fall under FERC's Wholesale Distribution Access Tariff (WDAT).

However, these fixed, inflexible contracts are impeding the deployment of many DER systems by placing constraints on DER export permissions that may or may not be valid by the next year, or even the next month or week. As the DSOs implement their Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS), these systems are expected to be able to provide the assessments necessary to permit flexibility in contracts and operational flexibility. In the near future, ADMS and DERMS are expected to be capable of extensive communications, enabling operational flexibility of DERs to become a reality.

Load power imports. DSOs have an obligation to serve customer loads. When studies identify possible overload conditions occurring when a customer requests service for additional load, this obligation requires the DSOs to upgrade existing distribution circuits and substations, and to construct new distribution system facilities. The growing demand for electric vehicles, including for charging stations able to fast-charge large semi-trucks, leads to a rapid increase in the demand for upgrades to the distribution system. Energization requirements are also expanding for facility heating, electric appliances, data centers, crypto-mining and blockchain processing, cloud-based services, building electrification, and many other electrification needs. The DSOs are currently obliged to meet these loads even if the maximum load only occurs infrequently, if at all, based on worst-case scenarios.

Many of these loads, however, are *controllable*, many of them could be shifted in time and/or location without negatively affecting the end user. If DSOs were able to develop Limited Load Profiles that included flexibility on when and from where (source of generation) these loads could be served, they could avoid or at least defer costly distribution system upgrades. In certain facilities, the import of power for controllable loads might be limited only until upgrades could be implemented[14], but nonetheless these facilities could be implemented and connected, so long as the Limited Load Profile included flexibility to limit the demand associated with these loads.

In the High DER Future, the DSO's ADMS/DERMS systems could assess the impact on the distribution circuits and substations of power import required for loads as well as the power export from DER. These assessments would permit the DSO to establish more accurate limits on when power imports might be limited. Therefore, in an

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[12] *The DSOs and DER implementers can develop mutual agreements to vary or waive some of the requirements.*

[13] *Decision 16-06-052 June 23, 2016, Rulemaking 11-09-011 Alternate Decision Instituting Cost Certainty, Granting Joint Motions To Approve Proposed Revisions To Electric Tariff Rule 21 Tariff, And Providing Smart Inverter Development A Pathway Forward For Pacific Gas And Electric Company, Southern California Edison Company, And San Diego Gas & Electric Company*

[14] Load Control Management Systems (AL 5138-E-A)

equivalent structure to Interconnection Agreements for DER, Limited Load Profiles could (optionally) identify flexible power import limits for certain customer facilities. In parallel to Rule 21 Tariff for DER interconnections, Rules 2, 15, and 16 (and Rules 29 and 45 for EVs) would need to take into account the addition of power import limits.

Operational flexibility for power export and import. After lengthy discussions, the SIOWG embraced many of the flexibility concepts and introduced some new terms to describe them. These included the following concepts.

- **Operational Flexibility in contractual Interconnection Agreements and/or Limited Load Profiles**. Interconnection agreements have been viewed as fixed contracts that would not be changed for the life of that contract. However, the grid is changing rapidly and a power export limit or a power import limit that seems fixed today could very well be different tomorrow. For this reason, flexibility should be added to Interconnection Agreements **and/or Limited Load Profiles** in the form of **firm export and/or import limits** and additional **non-firm export and/or import capacities** which could be authorized in the future for specific time periods.
- The **firm export and/or import limits** would reflect the DER operator's agreement with DSO based on the DER facility's generation, storage, and load capabilities, the DSO's assessment of current capacity constraints on the grid, and any decisions on upgrading the grid to minimize those capacity constraints.
- The additional **non-firm export and/or import capacity** would reflect the DER operator's additional potential flexibility on being able to export and/or import additional power based on the DSO's assessment of grid capabilities at a future point in time.
- The "**operational export and/or import limit**" would reflect the DSO authorized export and/or import limit at any point in time based on the firm and non-firm export and/or import limit specified in the DER operator's agreements with DSO. When authorized by the DSO, the DER systems could then provide additional support to the distribution system, such as improved export and/or import management of congestion.

This approach of using firm export and import limits and non-firm export and import capacity is new. DSOs will require additional studies, assessments, and near-real-time information to determine how much and when to authorize the non-firm export and/or import capacity to be operationalized. Many of the tools for such evaluations are (probably) in the designs for their ADMS/DERMS capabilities, but more tools and more detailed and timely information on the grid conditions may also be needed. In addition, regulatory procedures will need to be adjusted or improved to address the many issues that could arise from this new approach. Some of those regulatory issues are identified in this report, but it is expected that many additional issues will become evident over time.

Requirement for the development of operating principles and the implementation of planned technologies. Operating principles and prioritization of DER access to available distribution capacity need to be developed when implementing the new concepts introduced in the report. For example, it will be necessary to identify an equitable methodology for allocating available non-firm distribution capacity to different DER applications. Use of interconnection queue position might be a logical starting point. For operational scenarios, especially in the event that actual system conditions are different from the conditions assumed for purposes of the interconnection study, it will be necessary to identify how reductions in available non-firm and firm distribution capacity will be allocated among potentially effected DERs.[15] In addition, the DSO plans for their ADMS/DERMS capabilities will need to be assessed to ensure they can meet these new requirements.

[15] *At the transmission level, such allocations are determined on the basis of bid/offered prices. This approach, while highly efficient, is currently infeasible on the distribution system as the market systems and processes necessary to optimize distribution access on the basis of price do not exist.*

Handling of unused capacity. Operational flexibility could also result in the DSOs having more ability to handle unused capacity. This issue is discussed more in Annex B.

1.4 CPUC Jurisdictional Definitions

1.4.1 CPUC Electric Utility Jurisdictions

The CPUC has jurisdiction over three Investor Owned Utilities (IOUs): Pacific Gas and Electric Company's (PG&E), Southern California Edison's (SCE), and San Diego Gas & Electric's (SDG&E) as well as three privately owned small and multi-jurisdictional utilities (SMJUs): Bear Valley Electric Service (Bear Valley), Liberty Utilities (CalPeco Electric) LLC (Liberty), and PacifiCorp, d.b.a Pacific Power (PacifiCorp).

The three IOUs use Rule 21 Tariff requirements for interconnecting DER systems to their grids. PacifiCorp does not utilize Rule 21 Tariff, but instead uses interconnection processes under its Open Access Transmission Tariff (OATT), consistent with Federal Energy Regulatory Commission (FERC) requirements. The Commission has not required PacifiCorp to implement Rule 21 Tariff but accepts PacifiCorp's existing interconnection processes for the interconnection of smaller facilities. In Decision (D.) 07-07-027, the Commission required that PacifiCorp "follow the same principles of timely review and disposition of interconnection requests as in Rule 21 Tariff for other utilities without requiring that [it] file [its] own version of Rule 21 Tariff, amend then current rules, or file another interconnection protocol."

1.4.2 CPUC's Rule 21 Tariff for DER Interconnections

According to Rule 21 Tariff, "Interconnection" and "Interconnected" mean the physical connection of a generating facility (storage is considered as generation for the purposes of Rule 21) in accordance with the requirements of applicable electrical corporation rules so that parallel operation with the electrical corporation's distribution or transmission system can occur (has occurred). The Rule 21 Tariff includes functional requirements for interconnection as described in Annex A.

1.4.3 CPUC's Energization Rules for Interconnecting Loads

There is no formal definition of energization in CPUC rules. However, according to California laws AB 50 and SB 410, "energization" and "energize" mean connecting customers to the electrical distribution grid and establishing adequate electrical distribution capacity or upgrading electrical distribution or transmission capacity to provide electrical service for a new customer, or to provide upgraded electrical service to an existing customer. The determination of adequate electrical distribution capacity includes consideration of future load. Unlike the Rule 21 Tariff which includes functional requirements for DER interconnection, "energization" and "energize" do not include functional requirements related to connecting electrical supply resources. DSOs generally use the term "Service Agreement" for connecting customer loads to the distribution system, although other terms are sometimes used. For the purposes of this report, the term "Service Agreement" is used.

Three CPUC rules apply to interconnecting loads: Rule 2, Rule 15, and Rule 16:

- **Rule 2** addresses the physical and electrical characteristics of load service.
- **Rule 15** is the Tariff that governs the investor-owned electric utilities distribution line extensions, which are extensions of the existing distribution lines from the nearest permanent and available distribution facilities to commercial areas/neighborhoods. Rule 15 specifically requires new distribution line extensions to be built underground.

- **Rule 16** is the electric utility Tariff that outlines the rules and requirements for service line extensions, which are lines that connect the distribution lines to the customers' electric meters. Service line extensions are necessary to provide utility service when new residential/commercial/industrial facilities are constructed. Like Rule 15, Rule 16 also has an underground requirement for new customer facilities.

For the purposes of this working group report, the term "Limited Load Profile" is used to denote a contract between a DSO and a customer involving load limits.

1.4.4 CPUC EV Rules for Interconnecting Electric Vehicles

Electric vehicles while charging are covered under the CPUC's energization rules. Two CPUC rules apply to the interconnection of electric vehicle charging stations: Rule 29 and Rule 45.

- **Rule 29** is designed to help reduce the cost and simplify the process of providing Electric Vehicle (EV) infrastructure for commercial, industrial, and/or multi-family EV charging station projects.
- **Rule 45** is an optional new service pathway for separately metered EV charging sites outside of single-family homes. Rule 45 is an alternative to Rule 16.

Electric vehicles while discharging (V2G) are covered by the CPUC's Rule 21 Tariff. However, testing of V2G AC discharging is going to be addressed by UL 1741 Supplement C rather than Supplement B.

1.4.5 CPUC Tariffs versus DER Interconnection Agreements or Limited Load Profiles

CPUC establishes the Tariffs for interconnections with their rules. DSOs utilize those rules in their DER Interconnection Agreements as well as their load Limited Load Profiles. The agreements are contractual between the DSOs and their customers and contain many specific items related to the specific DSO, the specific location of the customer, and the specific needs of the customer. They usually require compliance with the CPUC rules although some exceptions can be made by mutual agreement between the DSO and the customer.

1.4.6 Limited Load Profiles

Although the term "Limited Load Profile" is being used in this document, it is only an informal term used for convenience, in comparison to Interconnection Agreement, which is formally used by the DSOs.

As operational flexibility is added to Limited Load Profiles, it could be useful to learn from the addition of capabilities to Rule 21 Tariff for DER interconnections. For instance:[16]

- The existing timeline reporting templates could be leveraged from Rule 21 Tariff, where the D.20-09-035 Ordering Paragraph 22 directed the DSOs to submit quarterly processing timelines reports. These reports could include data such as: project zip code, status, size, timeframe for various stages in the interconnection process (e.g., time for submission of interconnection request to time deemed complete).
- Repurpose Rule 21 Tariff efforts for load to streamline energization projects:
  - Interconnection Notification Only Approach (NOA) could become the Energization NOA, in which energization projects could be expedited if certain criteria are met, such as using load during periods where there is no need to upgrade the electric grid
  - Limited Generation Profiles could become Limited Load Profile
  - Utilize communication infrastructure to communicate net load and control timing of load

[16] *Interconnection and Energization Overview of Rules for Two Different Types of Distribution System Connections 4.A Matt Coldwell, CPUC, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250049&DocumentContentId=84767*

1.4.7 CPUC versus CAISO Jurisdictions

The CPUC has jurisdiction over distribution systems while CAISO has jurisdiction over transmission and sub-transmission systems, known collectively as the bulk power system.

The Rule 21 Tariff, now incorporating IEEE Std 1547-2018, covers DER system interconnections to the distribution system are planning to provide services to CAISO, even if they are interconnected to the distribution system, they are required to meet the Wholesale Distribution Access Tariff (WDAT) mandated by the Federal Energy Regulatory Commission (FERC). Some of the WDAT requirements are also provided in the IEEE Std 2800 for Inverter-Based Resources (IBR). CAISO has jurisdiction over WDAT, while the DSOs are responsible for ensuring the technical quality requirements of WDAT are met, even though it is the FERC Tariff.

1.4.8 Updates to Rule 21 Tariff with IEEE Std 1547-2018

Although the scope of the SIOWG references the Smart Inverter Working Group (SIWG) Phases 1 and 3 of the Rule 21 Tariff proceeding (R11-09-011)[17], recently the Rule 21 Tariff has been updated[18] to reference the IEEE Std 1547-2018 smart inverter functions.

However, even more changes may be underway. The IEEE Std 1547-2018 requirements are also being revised with the goal of publishing these revised requirements by 2025 or 2026. These revisions, although far from final, relate to many of the issues likely to occur in a High DER Future, including the following:

- Communication requirements beyond those already in IEEE Std 1547-2018
- DER storage functional requirements when charging
- Controllable loads in general
- Electric vehicles as DER
- Cybersecurity
- Differing requirements for DER systems or DER facilities (as opposed to individual DER units)
- DER scheduling

Although not all these issues may eventually be included in the forthcoming IEEE P1547 (2025/2026), they are expected to be discussed as part of the SIWG Rule 21 Tariff proceeding and/or in the High DER Future proceeding.

2 Terms and Definitions

2.1 Terms

Acronym	Meaning
ADERMS	Aggregator DER Management System
ADMS	Advanced Distribution Management System
Area EPS	Area Electric Power System

[17] *Annex A describes the history of the Smart Inverter Working Group (SIWG) and the three phases for including smart inverter functions.*
[18] *Decision 16-06-052 June 23, 2018*

Acronym	Meaning
BTM	Behind-The-Meter
CSIP	Common Smart Inverter Profile
CVR	Conservation Voltage Regulation
DER	Distributed Energy Resource
DER Facility	{equivalent to} Generating Facility
DER Operator	{equivalent to} Generating Facility Operator
DER System	{equivalent to} DER
DERMS	Distributed Energy Resource Management System (of the DSO)
DSO	Distribution System Operator
ELRP	Emergency Load Reduction Program
EMS	Energy Management System
EPS	Electric Power System
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FDERMS	Facility DER Management System
FTM	Front-of-the-Meter, equivalent to In-Front-of-the-Meter (IFM)
FERC	Federal Energy Regulatory Commission
IA	Interconnection Agreement
IBR	Inverter-Based Resource (see IEEE 2800)
ICA	Integration Capacity Analysis
IFM	In-Front of the Meter, equivalent to Front-of-the-Meter (FTM)
IOU	Investor-Owned Utility, e.g., PG&E, SCE, SDG&E
ISO	Independent System Operator
LGP	Limited Generation Profile[19]
LMP	Locational Marginal Pricing
Local EPS	Local Electric Power System
LSE	Load Serving Entities
NGOM	Net Generation Output Meters
OATT	Open Access Transmission Tariff
OI	Outline of Investigation (UL term)

[19] *See https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/rule-21-interconnection/limited-generation-profiles for the current status of LGP rulings.*

Acronym	Meaning
PCC	Point of Common Coupling == metering point == service point
PCS	Power Control System (as used in this report)
POC	Point of Connection
POI	Point of Interconnection
PPA	Power Purchase Agreement
PSPS	Public Safety Power Shutoffs
RA	Resource Adequacy
ROCOF	Rate of Change of Frequency
RPA	Reference of Point Applicability
SIWG	Smart Inverter Working Group
SIOWG	Smart Inverter Operationalization Working Group
SIO-CS	Smart Inverter Operationalization Cybersecurity Subgroup
V1G	Vehicle One-Way to Grid (charging only)
V2B	Vehicle Two-Way to Building
V2G	Vehicle Two-Way to Grid (charging and discharging)
V2H	Vehicle to Home
V2X	Vehicle to {charging and discharging to any system}
VGI	Vehicle Grid Integration (includes V1G, V2G, V2B, V2H, V2X)
VPP	Virtual Power Plant
WDAT	Wholesale Distribution Access Tariff

2.2 Definitions

The following are some definitions of terms used in this report. Many come from IEEE Std 1547-2018. Where a term is used in this report but not found here, it may be found in IEEE Std 1547-2018.

- **Active Power.** The power which is actually consumed or utilized in an AC circuit. It may also be called Real power and is the power that provides energy to electric circuits and loads. It is measured in kilowatt (kW) or MW.
- **Advanced Distribution Management System**. A software platform that supports the full suite of distribution management and optimization. An ADMS includes functions that automate outage restoration and optimize the performance of the distribution grid. ADMS functions being developed for electric utilities include fault location, isolation and restoration; volt/volt-ampere reactive optimization; conservation through voltage reduction; peak demand management; and support for microgrids and electric vehicles.

- **ADMS/DERMS.** Combined distribution and DER energy management systems. Sometimes used in this combination to indicate the joint assessments and planning studies of both the distribution system and the interconnected DER characteristics and capabilities. *Note: in this document, the term ADMS/DERMS is used as shorthand for all applications and tools needed to study, plan, assess, gather information, and issue requests and commands.*
- **Aggregator.** an entity that aggregates one or more DER systems for purposes of DER monitoring, DER energy management, and/or participation in the capacity, energy and/or ancillary service markets of the DSOs, RTOs, and/or ISOs.
- **Area electric power system (Area EPS).** An EPS that serves Local EPSs.
- **Business Case.** Description of business objectives or purposes that could be provided through regulations, procedures, and/or technology. Typically, business cases stay at a high level to focus on ***what*** or ***why*** a process is needed, but ***not how*** that process might be implemented.
- **Cease to energize.** Cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange.
- **Congestion management.** Strategy aimed at steering either the supply or demand of energy during peak periods, when the capacity of the grid or of individual circuits is reaching its limits.
- **Distributed Energy Resource (DER).** A source of electric power that is not directly connected to a bulk power system. [*Source IEEE Std 1547-2018*]
- **Distributed Energy Resource (DER).** DER includes both generators and includes distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, time variant and dynamic rates, flexible load management, and demand response technologies. Most DERs are connected to the distribution grid behind the customer's meter (BTM), and some are connected in front of the customer's meter (FTM). [*Source CPUC*[20]]
- **Distributed energy resources (DER).** DR includes distribution-connected renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response. *[Source California law*[21]]
- **Distributed Energy Resources Management System (DERMS).** a platform which helps distribution system operators (DSO) manage their grids that include significant numbers of distributed energy resources (DER).
- **Distributed Energy Resource (DER) operator.** Entity responsible for management and operation of their DER units and DER systems.
- **Distributed Energy Resource (DER) system.** Any grouping of DER units acting as a system. Equivalent to "DER" as defined in IEEE Std 1548:2018.
- **Distributed Energy Resource (DER) unit**. An individual DER device inside a group of DER that collectively form a system.
- **Distribution System**. The final stage in the delivery of electricity from the source of electric energy to the end user. The electric energy source could come from bulk power generators via the transmission system or could be distribution-connected distributed energy resource systems.

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[20] *CPUC DER Action Plan 2.0 04/21/202, 467470755, Page 24 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M467/K470/467470758.PDF*

[21] *https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=769 (defining "distributed resources" for purposes of utility deployment of these devices, technologies, and programs).*

- **Distribution System Operator (DSO)**. Entity responsible for ongoing planning and operation of the distribution system. The CPUC has jurisdiction over six DSOs: Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric, and 3 privately owned electric utilities.
- **Electric Vehicle (EV)**. A vehicle that can be powered by an electric motor that draws electricity from a battery and is capable of being charged from an external source. An EV includes both a vehicle that can only be powered by an electric motor that draws electricity from a battery (all-electric vehicle) and a vehicle that can be powered by an electric motor that draws electricity from a battery and by an internal combustion engine (plug-in hybrid electric vehicle).
- **Emergency Load Reduction Program (ELRP) (R.20-11-003, A.22-02-005).** The ELRP is a 5-year pilot program designed to pay electricity consumers for reducing energy consumption or increasing electricity supply during periods of electrical grid emergencies. The purpose of the ELRP pilot is to offer a new tool for the electric grid operators and utilities for reducing energy consumption or increasing electricity supply (e.g., discharging energy storage) during a grid emergency to reduce the risk of electricity outages when the available energy supply is not sufficient to satisfy the anticipated electricity demand.
- **Export.** Active power going through the PCC from (i) the customer with a Behind-The-Meter (BTM) DER facility to the Area EPS, or (ii) from an In-Front-of-the-Meter (IFM) DER facility to the Area EPS.
- **Facility DER Energy Management System (FDERMS).** A platform which helps DER operators manage the distributed energy resources (DER) within their facility. Alternate terms include Customer Energy Management System, Power Control System, Generating Facility Management System.
- **Firm Export Limit.** The contractual, not-to-exceed export limit in watts at the PCC. This may be a single limit or may be multiple limits per a schedule. This limit could be based on the DER capabilities, the DER owner requested limit, and/or the DSO-required limit for grid safety and reliability reasons.
- **Firm Import Limit.** The contractual, not-to-exceed import limit at the PCC. This may be a single limit or may be multiple limits per a schedule. This limit could be based on the DER capabilities, the DER owner requested limit, and/or the DSO-required limit for grid safety and reliability reasons.
- **Flexibility Operator.** Entity that provides market information to DER systems and/or DER aggregators. This entity might be the same company as the aggregator entity, but its function is to provide market information for the aggregator to use in managing the DER systems.
- **Grid.** Distribution system. Used interchangeably in this document.
- **High DER Future.** A CPUC Order Instituting Rulemaking to Modernize the Electric Grid for A High Distributed Energy Resources (DER) Future issued on July 2, 2021. The Order Instituting Rulemaking presents a preliminary scope and schedule for proceeding R.21-06-017 (the “High DER” proceeding). The new proceeding is the successor to the Distribution Resources Plans (DRP) proceeding (R.14-08-013). More details can be found in R.21-06-017.
- **IEEE Std 1547-2018.** IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, published in 2018.
- **IEEE Std 2030.5:2018.** IEEE Standard for Smart Energy Profile Application Protocol.
- **IEEE P1815.2.** Draft Standard Profile for Communications with Distributed Energy Resources (DERs) using IEEE Std 1815™ [Distributed Network Protocol (DNP3)].
- **Import**. Active power going through the PCC from the Area EPS to (i) the customer with a BTM DER facility, or (ii) an IFM DER facility.

- **Interconnection Agreement**. A contract between a DSO and a customer interconnecting their DER system to the distribution system.
- **Island**. A condition in which a portion of an Area EPS is energized solely by one or more Local EPSs through the associated PCCs while that portion of the Area EPS is electrically separated from the rest of the Area EPS on all phases to which the DER is connected. When an island exists, the DER energizing the island may be said to be "islanding".
- **Limited Load Profile**. Load limiting profile to be attached to the tariffs or service agreements governing energization of loads, including Rule 2, Rule 15, and Rule 16, plus Rule 29 and Rule 45 for EVs.
- **Load**. Devices and processes in a local EPS that use electrical energy for utilization, exclusive of devices or processes that store energy but can return some or all of the energy to the local EPS or Area EPS in the future.
- **Local electric power system (Local EPS)**. An EPS contained entirely within a single premises or group of premises.
- **Microgrid**. An interconnected system of loads and energy resources, including, but not limited to, distributed energy resources, energy storage, demand response tools, or other management, forecasting, and analytical tools, appropriately sized to meet customer needs, within a clearly defined electrical boundary that can act as a single, controllable entity, and can connect to, disconnect from, or run in parallel with, larger portions of the electrical grid, or can be managed and isolated to withstand larger disturbances and maintain electrical supply to connected critical infrastructure.
- **Minimum Export Requirement**. the contractually required minimum export in watts at the PCC. The DER facility would export at least the minimum active power during the specified time period.
- **Minimum Import Requirement**. the contractually required minimum import in watts at the PCC. The DER facility would import at least the minimum active power during the specified time period.
- **Near-Real-Time Communications**. Time latency of a few minutes between the occurrence of an event and the receipt of information on that event.
- **Non-Firm Export Capacity.** Mutually agreed contractual optional additional capacity in watts beyond the firm export limit, some or all of which could be exported if authorized by the DSO, based on current or forecast grid conditions. Such DSO authorization may be modified at any time if grid conditions change. Non-firm export capacity may consist of a single value or may be a schedule of multiple values indicating when some part of that non-firm export capacity may be available to be authorized by the DSO.
- **Non-Firm Import Capacity.** Mutually agreed contractual optional additional capacity in watts beyond the firm import limit, some or all of which could be imported if authorized by the DSO, based on current or forecast grid conditions. Such DSO authorization may be modified at any time if grid conditions change. Non-firm import capacity may consist of a single value or may be a schedule of multiple values indicating when some part of that non-firm import capacity may be available to be authorized by the DSO.
- **Non-Wires Alternative.** Any electrical grid investment that is intended to defer or remove the need to construct or upgrade components of a distribution and/or transmission system, or "wires investment".
- **Operational Export Limit.** the authorized export limit during any specific time period, based on the firm export limit plus any additional authorized non-firm export capacity. During abnormal conditions, the operational export limit may be less than the firm export limit.
- **Operational Flexibility**. The ability of a power system to respond to changes in electricity demand and generation.

- **Operational Import Limit.** the authorized import limit during any specific time period, based on the firm import limit plus any additional authorized non-firm import capacity. During abnormal conditions, the operational import limit may be less than the firm import limit.
- **Point of Common Coupling (PCC).** The point of connection between the Area EPS and the Local EPS. (IEEE Std 1547-2018). The transfer point for electricity between the electrical conductors of Distribution Provider and the electrical conductors of Producer. (Rule 21)
- **Point of Connection (POC).** Point where the DER unit is electrically connected to the Local EPS (BTM) or to the Area EPS (FTM).
- **Power Control System (PCS)**. A system consisting of one or more device(s) that electronically limits or controls the steady state AC and/or DC current(s) or power on conductors or busbars to programmable limit(s) or level(s). Alternate terms include Customer Energy Management System, Generating Facility Management System, Facility Distributed Energy Management System. [Source: draft UL 3141 Outline of Investigation]
- **Reactive Power**. The power which flows back and forth, meaning it moves in both directions in the circuit or reacts upon itself. Reactive power is measured in kilo volt-ampere reactive (kVar) or MVar. This reactive power does not perform any useful work in the circuit but can be utilized to modify the voltage.
- **Real-time Communications.** Time latency of less than 1 to 5 seconds between an event's occurrence and the receipt of information on it.
- **Reference Point of Applicability (RPA)**. The location where the interconnection and interoperability performance requirements specified apply.
- **Service Agreement**. A contract between a DSO and a customer connecting their load to the distribution system.
- **Smart Inverter**. Type of DER unit using controllable DC to AC converters. A “smart inverter” is an electronic device that converts direct current (DC) electricity generated by solar panels or other renewable sources into alternating current (AC) electricity for use in homes or the electric grid, with the ability to communicate, thus enabling them to respond to grid conditions and commands from controllers.
- **Smart Inverter Operationalization (SIO)**. Use of smart inverter capabilities to support distribution system operations. Implied in operationalization is that the necessary systems and equipment have been developed and deployed, along with the necessary rules and Tariffs. Although this term includes “smart inverter” it is really applicable to any DER.
- **Time latency**. Different time latencies as used in this document: real-time is sub-second to 1 second; near-real-time is 1 second to 5 minutes; hourly time is within one hour; daily time is within one day.
- **Time periods**. Different time terms as used in this document: short-term is a time period of 3-5 years; long-term is a time period of greater than 5 years.
- **UL 3141 Outline of Investigation for Power Control Systems (draft)**. Requirements covering Power Control Systems (PCS) used in Distributed Energy Resource (DER) systems which include one or more power sources in addition to the primary power source, typically the utility grid. PCS-LC (load control only applications) may consist of only the utility source, or a combination of the utility source and DER sources not controlled by the PCS-LC sized. The PCS electronically limits or controls currents to stay within defined limits and may consist of a single device or multiple devices operating together as a system.
- **Use Case**. Description of technical methods for supporting Business Cases. Use Cases may also be high level or may be detailed but are focused on ***how*** the process might be implemented.

- **Virtual Power Plant (VPP)**. A collection of small-scale energy resources that, aggregated together, can provide distribution services.
- **Wholesale Distribution Access Tariff (WDAT).** Tariff that describes the terms under which the DSO provides open access to its distribution system to wholesale customers seeking to interconnect generation facilities to a distribution system and deliver energy and capacity services to the California Independent System Operator (CAISO) controlled grid (using DSO's distribution system), or to deliver energy or capacity services from the CAISO controlled grid (using DSO's distribution system) to their customers.

3 Overview of SIOWG Process, Issues, and Results

3.1 SIOWG Process, Meetings, and Documents

The SIOWG determined that the discussion of operational flexibility warranted bi-weekly meetings, first to understand the issues, secondly to resolve what actions might be taken by the CPUC in the near-term to prepare for the High DER Future, and eventually to develop the Working Group Report (this document). The following actions were taken:

- Bi-weekly meetings of 1.5 hours each, starting January 25, 2022
- Material for each meeting, including agendas and updated documents, prepared by Xanthus
- Most meetings captured in videos
- Open discussions and chat inputs by participants during meetings
- Presentations from participants, including the DSOs under CPUC jurisdiction
- Assignment of action items to specific participants
- Comments and tracked changes on documents uploaded to the Verdant SharePoint site
- Development of draft documents between meetings, including a spreadsheet for prioritizing the use cases, draft Business Cases, draft Use Cases, and a draft Working Group Report combining the Business Cases and Use Cases.
- Review of draft SIO Working Group Report by CPUC staff for accuracy and readability
- Update of draft SIO Working Group Report based on CPUC staff comments
- Delivery of the final SIO Working Group Report to the CPUC High DER Future [21-06-017] Service List to be followed by a ruling at a later date requesting on the record party comments

The following actions are planned after the finalization of the SIO Working Group Report:

- Development of draft SIO Staff Proposal reflecting formal comments on the Final SIO Working Group Report, staff research and analysis, and consultant content contributions
- Review of draft SIO Staff Proposal by the Energy Division Management and CPUC Decision Makers
- Delivery of ED SIO Staff Proposal to OIR parties for formal comments and workshop.
- CPUC Decision on SIO Staff Proposal and SIOWG Reports.

3.2 Clarification of Scope Issues During WG Discussions

At the beginning of the SIOWG effort, it became clear that several issues had to be discussed and clarified with the SIOWG members and the CPUC. These are shown as *Question*, followed by the *Result* of the discussions.

Although some of the issues overlapped, they were each included separately so that it could be very clear what the discussions covered. These were the following:

- **Use Case Evaluations.** ***Question*: “***How Should Use Cases be Evaluated?*” ***Result***: Use Cases should be evaluated based on the Scoping Memo**,** namely that smart inverter operationalization use cases should be prioritized and implemented to leverage the operational flexibility capabilities of smart inverters to provide value to grid operators and ratepayers.
- **Smart Inverters vs. Other Types of DERs.** ***Question*:** *“Is the Scoping Memo only relevant for DER systems that contain smart inverters?”* ***Result:*** The term “smart inverter” was originally used for photovoltaic systems and eventually energy storage systems whose inverters had the ability to manage active power and reactive power in response to signals from their controllers. Over time, many other types of generating systems and load control systems were found capable of providing similar responses if managed by power control systems. Therefore, systems using smart inverters became a subset of a more general category of energy systems, termed “distributed energy resources” or DER. It was thus agreed that any type of DER system that can provide the operational flexibility described in the use cases can be included. This includes generators with or without inverters, energy storage systems, controllable loads, generating facilities (containing different types of generators, storage systems, and loads), and virtual power plants.
- **Contractual Agreements vs Rule 21 Tariff.** ***Question*: “***Should Use Cases be Considered as Contractual Interconnection Agreements (or Limited Load Profiles) and/or as Potential Additions to Rule 21?*” ***Result***: The Use Cases will be used primarily in contractual agreements between the DSO and DER owner which could form a “pathway” toward eventually defining some of the flexibility recommendations in new tariffs. However, they may also be used by CPUC OIRs or other agencies to initiate rulings and/or recommendations within their domains.
- **PoC vs PCC.** ***Question*: “***Should the Use Cases Address Only the Requirements at the PoC or Also at the PCC?*” ***Result***: The Use Cases can indicate whether the Reference Point of Applicability (RPA) is the PoC or the PCC or can state that either the PoC or the PCC would work. Contracts based on the Use Cases can determine which will be the RPA: PCC, PoC, or other metered location.
- **Active Power Constraints Scope.** ***Question*:** “*Should Active Power Constraints Address Only Maximum Export Limits?*” ***Result***: Although the Rule 21 Tariff function is to Limit Active Power Exports, similar active power constraints can and will also be defined in the Use Cases: i.e., Maximum Active Power Export, Minimum Active Power Export, Maximum Active Power Import, & Minimum Active Power Import.
- **Management of Import.** ***Question*: “***Can Use Cases Address the Management of Loads in particular import limits?*” ***Result***: The Use Cases can describe the utilization of smart inverter-based DER for managing load. For example, if the RPA is the PCC, the Use Case can describe the management of loads as a capability or requirement for the DER. As a result, import limits can be addressed.
- **Electric Vehicles as DER.** ***Question*: “***Can Use Cases Address V1G Electric Vehicles as DER While Charging or Only V2G EVs (while discharging and charging)?*” ***Result***: The Use Cases can include EVs with V2G capabilities as DER, and, if in the same facility with smart inverter-based DER, can include EVs while charging as load, as defined in IEEE Std 1547-2018.
- **Validation and Performance Requirements.** ***Question*:** “*How Should Use Cases Address Validation and Performance Issues?*” ***Result***: The Use Cases *may*, *but do not need to*, include validation and performance requirements for meeting the operational requirements described in the Use Cases.
- **Use Cases for ISO Services.** ***Question*:** “*How Should Use Cases Address ISO Services Provided by DER?*” ***Result***: The Use Cases may include services that would typically be useful to ISO grid operators, such as

frequency support (e.g., the "frequency-watt" droop service is already included in IEEE Std 1547 and Rule 21), even if the DER systems are interconnected using the WDAT Tariff.

- **Compensation to DER Owners**. ***Question*: "***Many actions taken by DER owners might involve incentives or compensation – are there any implications to the scope of the SIOWG?* ***Result***: Whether an action is compensated or simply mandated is out-of-scope, so the actions may be discussed but not whether any incentives are applied.

3.3 Overview of the SIOWG Business Cases

3.3.1 Definitions of Business Cases versus Use Cases

Another issue was also raised by the CPUC: Are the SIOWG results Business Cases or Use Cases, and what are the differences?

The CPUC needs to justify actions, so Business Cases which identify goals are more appropriate for such justifications. However, what actions might be needed for achieving those Business Case goals must be described in Use Cases. The difference between the two is:

- **Business cases** describe business objectives or purposes that could be provided through regulations, procedures, and/or technology. Typically, business cases stay at a high level to focus on ***what*** or ***why*** a process is needed, but ***not how*** that process might be implemented.

  The goal of a business case is to include a clear and detailed explanation of the problem or opportunity that the stakeholders are facing, the goals and objectives of the potential solutions, and the identification of use cases that could be taken to achieve those goals. Business cases stay at a high level to focus on the "what" and the "why" this process is needed. The audience for the business base includes policymakers and other stakeholders.

  Business cases are often used as a starting point for the development of one or more potential technology solutions through **use cases**, and are used to guide the design, development, testing, and deployment of those solutions.

- **Use cases** describe the different ways the goals of business cases might be achieved and are used to determine ***how*** to achieve the business case goals. They include descriptions of the procedures and/or technologies involved and can include a list of actions or event steps typically defining the interactions between a role (actor) and a system to achieve the business case goals.

  Often there is more than one possible technology or method for meeting those goals, and sometimes the same use case can meet or partially meet the goals of multiple business cases. In addition to technical challenges, regulatory issues can also impact which use cases may be more practical or timely to achieve.

Due to the complexity of issues related to operational flexibility, the SIOWG first developed 7 Business Cases that could be used to justify specific processes (Use Cases) (see Figure 1).

High Priority Business Cases (Why, What Purpose) and their Allocated Use Cases (Technical How)

- **Business Case A**: Operational Flexibility in DER Interconnection Agreements
  - Use Case #A1: Scheduled Maximum Export Limit (*LGP*)
  - Use Case #A2: Commanded Maximum Export Limit
  - Use Case #A3: Minimum Generation Export Requirement
  - Use Case #A4: Maximum Scheduled or Commanded Import Limit
  - Use Case #A5: Situational Awareness
- **Business Case B**: Operational Flexibility during Abnormal Conditions
  - Use Case #B1: Scheduled Maximum Export Limit
  - Use Case #B2: Commanded Maximum Export Limit
  - Use Case #B3: Minimum Generation Export Requirement
  - Use Case #B4: Maximum Scheduled or Commanded Import Limit
  - Use Case #B5: Situational Awareness
- **Business Case C**: Operational Flexibility for Distribution Services under Normal Conditions
  - Use Case #C1: Scheduled Maximum Export Limit
  - Use Case #C2: Commanded Maximum Export Limit
  - Use Case #C3: Minimum Generation Export Requirement
  - Use Case #C4: Maximum Scheduled or Commanded Import Limit
  - Use Case #C5: Situational Awareness
- ***Business Case D**: Operational Flexibility through DER Voltage Support*
  - *No high priority requirements*
- **Business Case E**: Operational Flexibility for Electric Vehicles Providing Distribution Services
  - Use Case #E1: EV Peak Power Limiting (Demand Response)
  - Use Case #E4: Volt-Watt Response by EVs
  - Use Case #E8: Coordinated Charge/ Discharge of EVs to Ensure Desired State of Charge is Reached at the Requested Time
  - Use Case #E9: V2G EV as DER (Meeting Rule 21 requirements)
  - Use Case #E12: Watt-Var function
  - Use Case #E15: Limit Active Power Export function
- **Business Case F:** Operational Flexibility for Community Microgrids
  - Use Case #F1: Acting as a VPP
  - Use Case #F2: Community microgrid islanding process
  - Use Case #F3: Community microgrid management when islanded
- **Business Case G**: Operational Flexibility for DER Providing ISO Grid Services (High priority for CAISO)
  - Use Case G1: Fast Frequency Response (FFR)
  - Use Case G2: Synthetic or Artificial Inertia Frequency-Active Power
  - Use Case G4: Operating Reserve (Spinning Reserve)
  - Use Case G16: Default Settings and Actions if Communications are interrupted
  - Use Case G17: Unintentional Islanding

Figure 1: Business Cases and their Allocated Use Cases

Overviews of these Business Cases are described in the following sections.

3.3.2 Business Case A: Operational Flexibility in DER Interconnection or Limited Load Profiles

Business Case A (see Section 4.1 for more details) envisions the High DER Future to include flexibility in Interconnection Agreements related to export limits and/or Limited Load Profiles for import limits. Export limits currently are fixed when the Interconnection Agreement is signed, whether they are an implicit limit based on the DER capacity, a single explicit limit included in the agreement, or a set of scheduled limits determined by the DSO for safety and/or reliability purposes, such as the Limited Generation Profile (LGP) effort. At this time, limits are not generally placed on imports except to give the DSO time to implement any necessary upgrades to the distribution system in the context of Rule 21 Tariff. The need for import limits, however, may change as more electric vehicles charge from the grid.

The envisioned flexibility would require Interconnection Agreements to include firm export limits, but could, optionally, include additional non-firm export capacity. The DER operator could only use this non-firm capacity if the DSO authorized it: the DSO would assess the grid capacity for the (electrical) location of the DER facility and, if more capacity was available, would then authorize the DER operator to utilize some or all of this extra non-firm export capacity during specific time periods (hours, days, days-of-the-week, weeks, months) as "operational limits" (see the example in Figure 2).

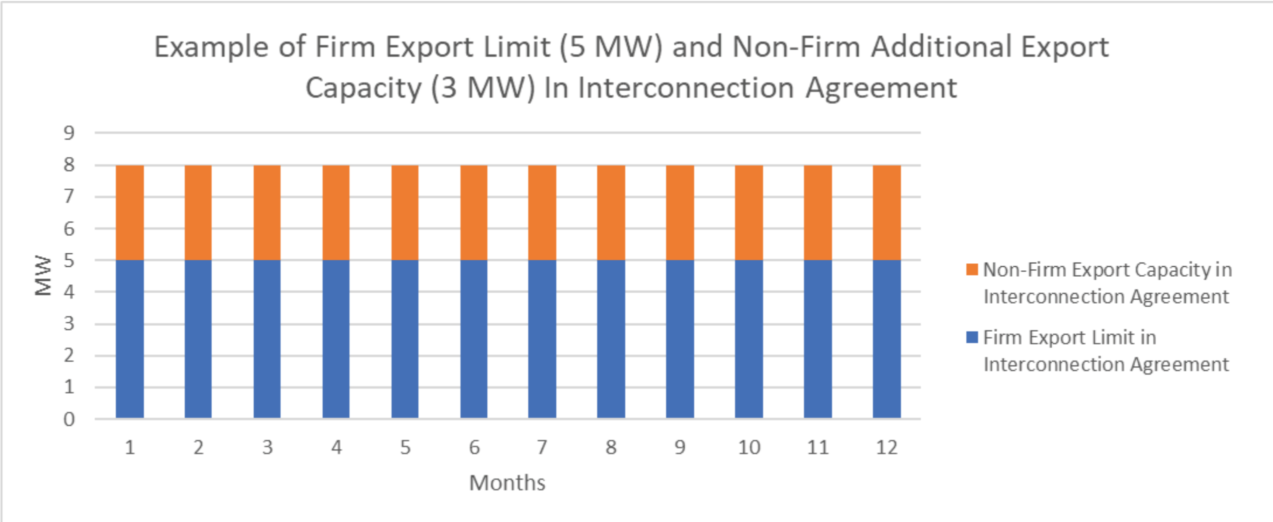

Figure 2: Example of Firm Export Limits and Additional Non-Firm Capacity in Interconnection Agreement

An example of an LGP schedule with firm export limits and non-firm export capacity is shown in Figure 3.

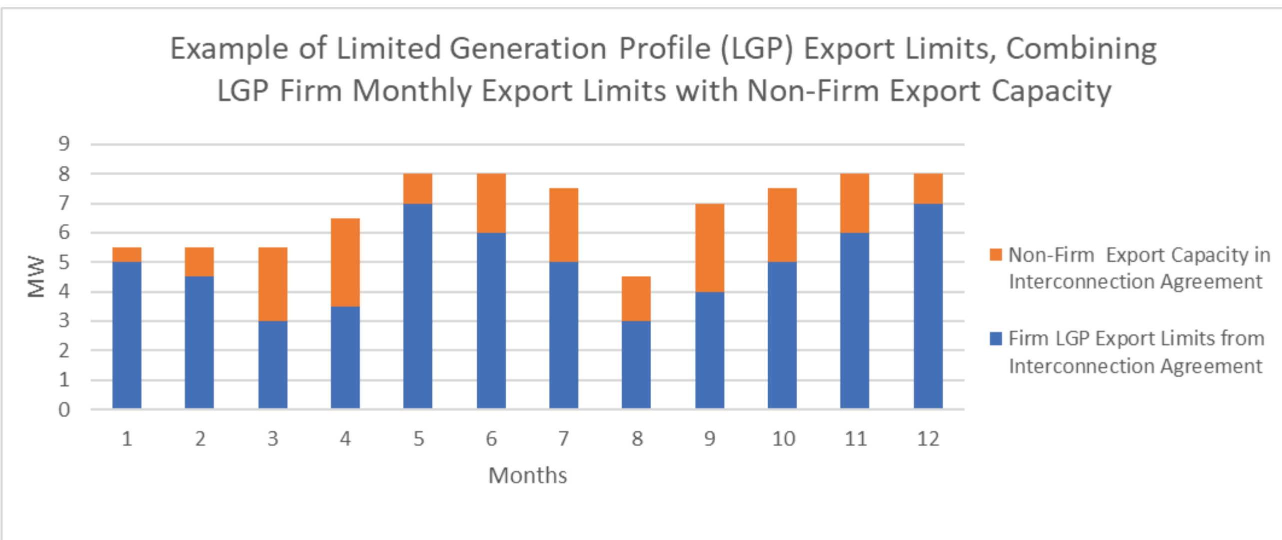

Figure 3: Example of a Limited Generation Profile in an Interconnection Agreement

The operational flexibility could also extend *optionally* to import limits by including firm import limits (per scheduled times as is currently possible for export limits) as well as additional non-firm import capacity that could be used if authorized by the DSO (see the example in Figure 4). This approach might be used to avoid, minimize, or defer distribution system upgrades, whether paid for by the DER owner or by ratepayers. The flexibility to manage exports and imports more dynamically could also help California meet its carbon neutrality goals by allowing more capacity to be used in the distribution system.

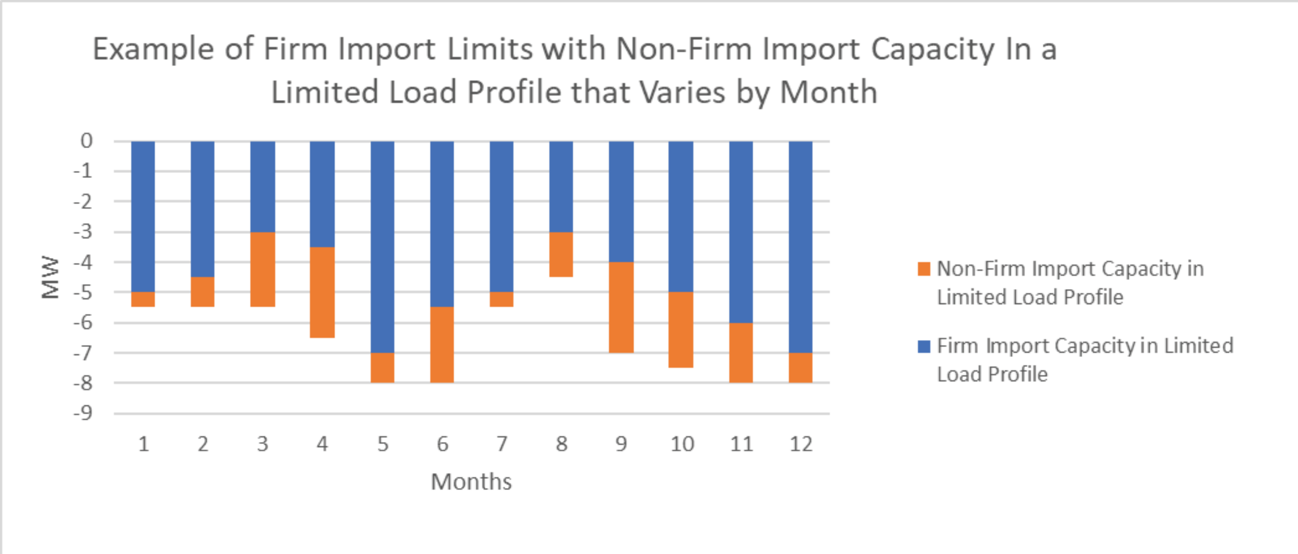

Figure 4: Example of Firm Import Limits and Additional Non-Firm Import Capacity in Limited Load Profiles

Although incentives and/or compensation are out-of-scope for the SIOWG, it may be that this shift in managing the export and/or import of power could involve compensation.

3.3.3 Business Case B: Operational Flexibility during Abnormal Conditions

Business Case B (see Section 4.2 for more details) addresses the DSO capabilities for providing information to DER operators before or during transitions to abnormal grid configurations. Abnormal conditions often require mandatory DER and load operational restrictions or actions due to the grid becoming operationally different from its normal operating condition.

Business Case B focuses on the ***mandatory*** actions that DSOs require DER systems to take, such as reducing exports or imports during or in anticipation of abnormal conditions, while Business Case C involves ***voluntary*** actions initiated by DER operators due to an incentive (such as demand response), under normal conditions or even possibly as a voluntary response to potentially abnormal grid conditions such as a pending heat wave. The key difference is whether there are mandates or voluntary actions due to incentives. The results may be similar, but the regulatory aspects are different.

There are three possible situations where abnormal conditions may occur:

1. **Real-time localized emergency condition.** In this condition, an unanticipated emergency condition occurs without advanced warning (e.g., car hits pole). In this condition, the grid will need to be reconfigured to isolate the issue and restore power to customers. Due to the grid being reconfigured, DER operations may need to be modified quickly to prevent unsafe situations and/or to minimize performance impacts (e.g., voltage problems or outages).
2. **Planned grid maintenance condition.** In this condition, an anticipated temporary grid modification is planned to perform certain types of grid maintenance (e.g., replacement of power lines of other equipment). For these types of conditions, it may be possible to determine the DER modifications and coordinate such modifications with the DER operator prior to the commencement of grid maintenance.
3. **Forecast system emergency conditions.** For these conditions, forecasts of pending storms, heat waves or PSPS events may cause the DSOs to take preventative actions such as reconfigurations that could also require DER operators to reduce exports or imports below their firm limits.

In the High DER Future, DER operators could proactively take additional steps to minimize the impact of abnormal situations (e.g., planned or forecast conditions, as well as response to actual emergency conditions). Where there are resource adequacy issues, the DSOs could provide information to DER operators about the nature of the abnormal situation and issue commands (as schedules or direct control) to minimize impacts (see Figure 5). Therefore, this business case addresses the DSO capabilities for providing such information and commands to DER operators, preferably before transitions to abnormal grid configurations and, when possible, even during emergency events (see the example in Figure 5).

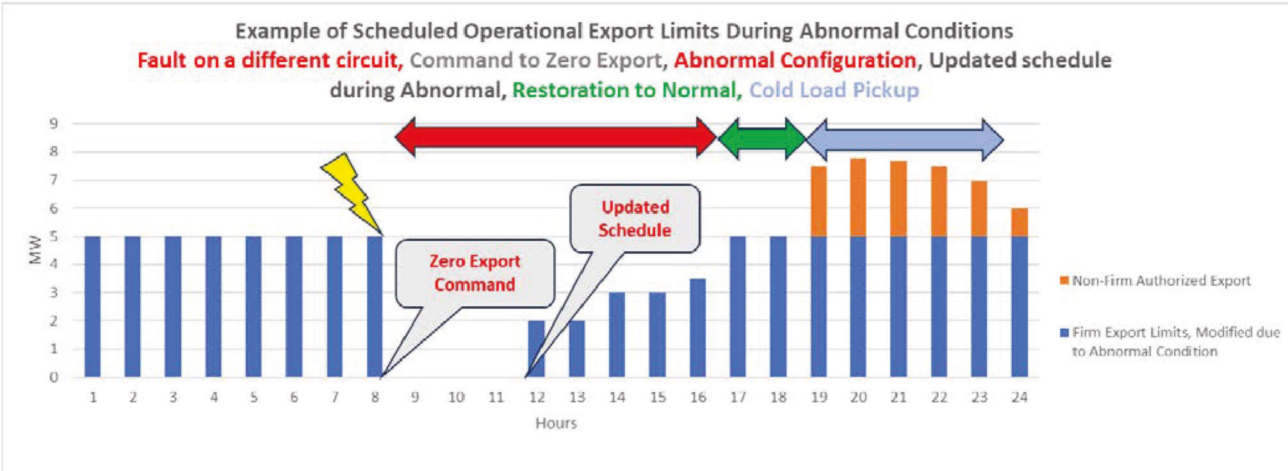

Figure 5: Example of Scheduled Operational Export Limits during Abnormal Conditions

3.3.4 Business Case C: Operational Flexibility for Distribution Services under Normal Conditions

Business Case C (see Section 4.2.4.5 for more details) addresses the operational flexibility requirements and capabilities for providing DER services to support DSOs, communities, CAISO, DER owners / aggregators, and society under normal grid conditions in the High DER future. As noted in Business Case B, DSOs may require **mandatory** actions under abnormal conditions. In Business Case C, DER operators may **voluntarily** take actions in response to incentives under normal conditions, or even if there may be pending abnormal conditions but the DSOs are not (yet) mandating specific actions. For example, the Emergency Load Reduction Program (ELRP) (R.20-11-003), when triggered by a pending heat wave, is designed for DER operators to *voluntarily* reduce load in return for some form of compensation, thus providing a service to the DSO.

These DER services will become increasingly necessary as additional electrification (e.g., electric vehicles) rapidly occurs, as increasing numbers and capacities of DER systems are interconnected, and as improved DSO ADMS/DERMS capabilities are available that could be used to detect when grid conditions are strained as well as when they do not have voltage or congestion problems.

The focus of Business Case C is to optimize the use of firm export and/or import limits and non-firm export and/or import capacity to support different DER services. There is not a clear demarcation between DER services that are focused only on providing safety and reliability support to the DSO's distribution system versus those that may support other stakeholders (e.g., CAISO, communities, DER owners, and society). Some terminology, however, may be useful to distinguish between the goals of DER services provided in support of different objectives:

- **DSO services** provide safety and reliability support to the distribution grid, such as limiting exports or imports to minimize overloads and providing voltage support.

- **Community services** are focused on providing services to customers within a community, such as using community microgrids for financial purposes, and, when islanded, for reliability purposes. As an example, a pending storm may cause a community microgrid to prepare for possible islanding to avoid outages from impacting their customers. This preparation may include operations such charging storage systems ahead of an emergency or permitting the export of non-renewable power (e.g., from stationary energy storage systems or EV V2G) if permitted by the DSO.
- **Ratepayer services** support the use of DER systems to minimize the necessary distribution system upgrades provided by DSOs.
- **CAISO services** are focused on providing services to CAISO (see Business Case G).
- **DER aggregator or owner services** are focused on providing benefits to DER aggregators or owners such as supporting their business requirements, permitting energy arbitrage actions for financial benefits, and utilizing their DER versus alternate resources to provide grid support.
- **Societal services** are focused on DER capabilities for supporting California and ratepayers on progressing toward California's 2045 goals for carbon neutrality.

One example of DER services is the use of operational flexibility to provide more accurate capacity limits for Limited Generation Profile (LGP) DER implementations, where the DSOs have authorized additional non-firm export of power t over the year, month, day, or even hour of the day (see example in Figure 6).

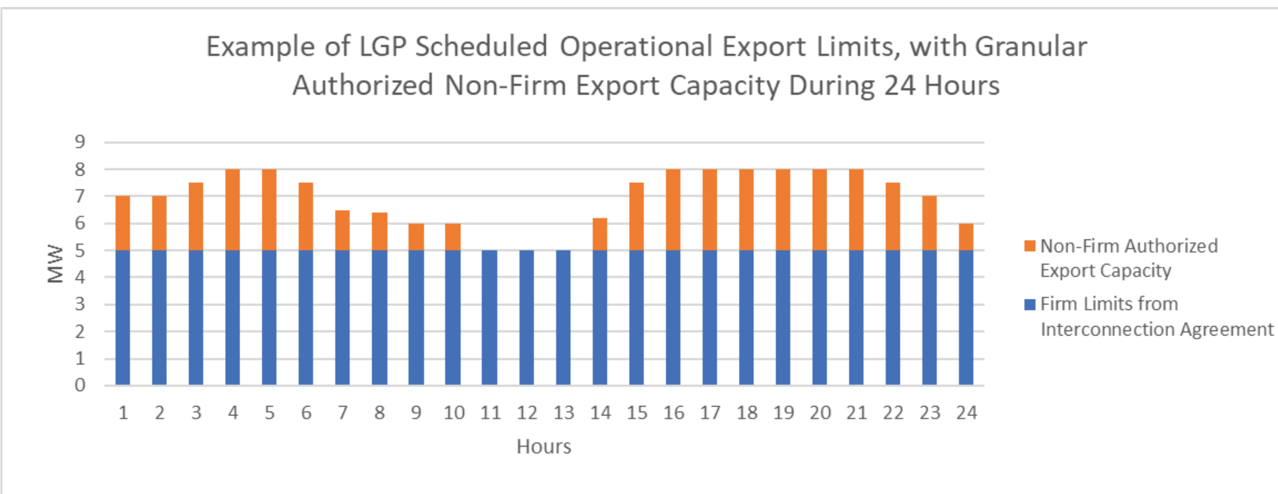

Figure 6: Example of Scheduled Operational Export Limits for Limited Generation Profile

Another example is the use of Minimum Export Requirement to provide resource adequacy when congestion or other factors are limiting the necessary generation for the load being served on a circuit. This service may be particularly critical during heat waves or if PSPS events are occurring (see Figure 7).

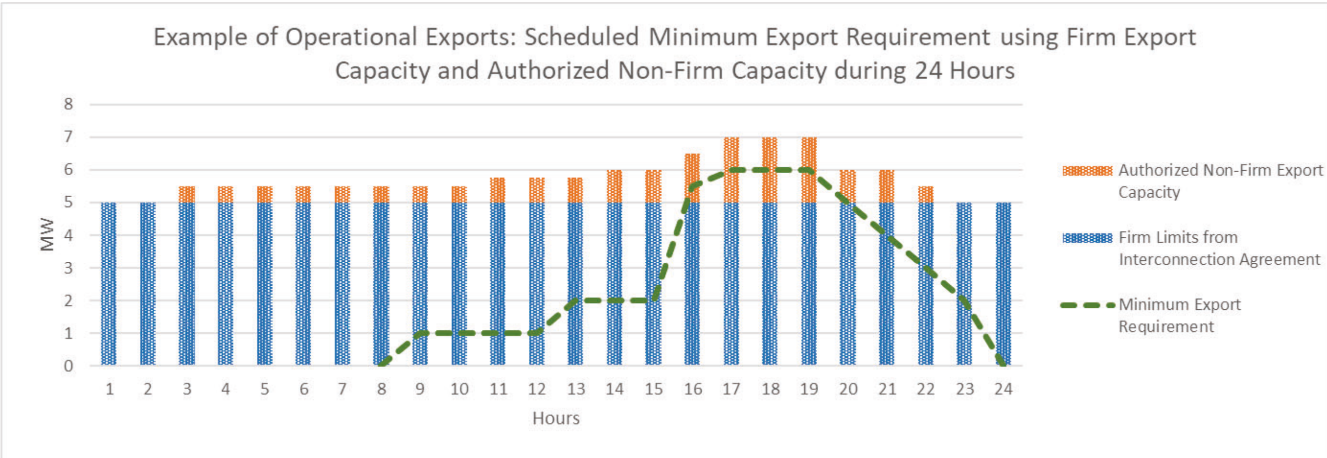

Figure 7: Example of Scheduled Minimum Export Requirement

It is not expected that DER systems will always utilize all the additional capacity allocated to them, so the actual exports should be metered (see example in Figure 8).

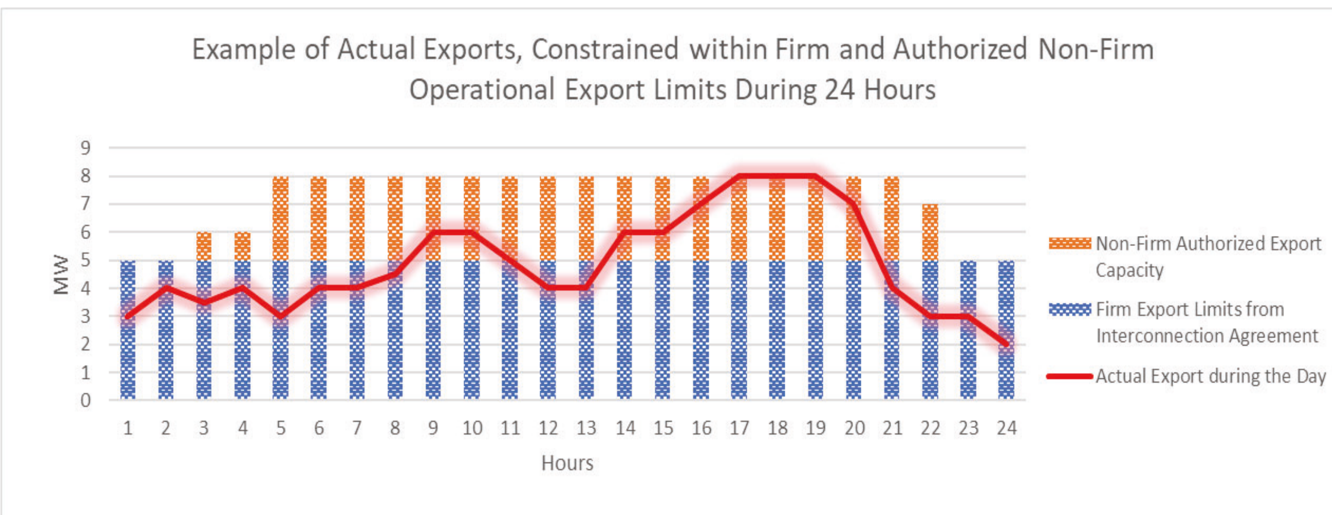

Figure 8: Example of Actual Exports Constrained by Authorized Operational Export Limits

Actual exports and imports could be constrained between the authorized export and import limits and minimum export and import requirement, as shown in Figure 9.

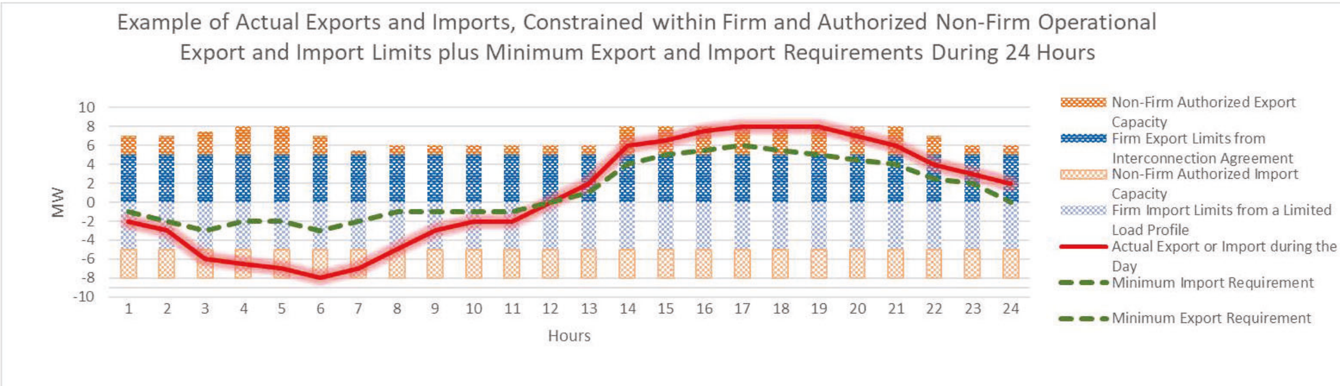

Figure 9: Example of Actual Exports and Imports Constrained between Authorized Operational Limits and Minimum Export and Import Requirements

If, over time (weeks, months, years), it becomes clear that a DER system is not utilizing all its allocated non-firm export or import capacity, this *unused non-firm capacity* could be allocated to other DER systems. One method to allocate or reallocate unused capacity could be to request DER systems to provide forecasts of what non-firm capacity they would like to use, so the DSO could authorize only that non-firm capacity to them, and then allocate any unused capacity to other DER systems. This would permit them to allocate capacity more fairly and effectively.

Although a different procedure might be needed, *unused firm capacity* over months or years could also be reallocated to other DER systems, thus avoiding stranded capacity.

3.3.5 Business Case D: Operational Flexibility through Voltage Support by DER

Business Case D (see Section 7) addressed voltage support by DER but it was not identified as high priority, so no use cases were developed for possible voltage support distribution services. Currently the volt-var function and the volt-watt functions are in the Rule 21 Tariff and could be used if requested by the DSO. Therefore, no additional operationalization capabilities were identified.

If during the assessment of Business Cases A, B, and C, however, the ability and need to manage voltage support via schedules and commands becomes more evident, Business Case D could be revisited. For instance, schedules for Volt-Var and/or Volt-Watt support could be provided by the DSOs to certain DER facilities to provide voltage support for energy efficiency.

For instance, these two voltage-support functions could be significant in fine-tuning Conservation Voltage Regulation (CVR) levels on circuits to potentially realize 1-2% efficiency savings across all areas in which they are employed. Voltage drops over distance and must be boosted at the regulating device in order to ensure that it falls within established parameters further "downstream" from the energy source, including with DER sources and bi-directional power flow on the lines. Using these voltage-support functions at intermediate locations would enhance operational voltage efficiency.

3.3.6 Business Case E: Operational Flexibility for Electric Vehicles Providing Distribution Services

Business Case E (see Section 8 for more details) addresses the capabilities and potential requirements for Electric Vehicles (EVs), and electric transportation in general, to provide distribution grid support services while charging

(V1G) and/or discharging (V2G). These services are similar to those provided by grid-connected DER in Business Cases A, B, and C. Although similar, the ability of electric vehicles to provide grid services has many differences from stationary DER due to their roaming capability, driver decisions that are not related to energy or price, and the proprietary EV Original Equipment Manufacturer (OEM) testing and certification requirements that are separate from any testing and certification of Electric Vehicle Supply Equipment (EVSE).

Business Case E reviewed the potential distribution grid support services that could be provided by EVs to determine which were deemed the highest priority, based on practical issues such as the capabilities of current EV and EVSE engineering designs, timeframe for EV manufacturers to provide those capabilities, and the need for specific grid services. The impact of large numbers of EVs charging on the grid, whether a managed fleet of EVs or uncoordinated individual EVs on the same feeder was also considered under this Business Case.

3.3.7 Business Case F: Operational Flexibility in Community Microgrids

Business Case F (see Section 9 for more details) addresses community microgrids (microgrids that include more than one customer) that use portions of the distribution system as part of the microgrid (thus containing equipment under the jurisdiction of the CPUC).

Community microgrids can act as Virtual Power Plants (VPPs) while connected to the grid. They could have firm export and/or import limits as well as non-firm export and/or import capacity which could be authorized at different times by the DSO. These VPPs could be managed and provide energy services just like any other DER or load facility covered by Business Cases A, B, and C. Internal to the microgrid, however, firm and non-firm limits and capacity could be allocated to individual customers so long as the net export or import does not exceed the VPP's allocated operational limits.

When islanded, community microgrids still contain equipment under CPUC jurisdiction and the DSOs would be required to maintain the same safety and reliability requirements in coordination with the microgrid operator. Of relevance to this report, these islanded microgrids could also take on the role of the DSO to allocate firm and non-firm limits to individual customers to balance generation and load within the microgrid and to meet the community ratepayers' requirements for fairness and efficiency.

3.3.8 Business Case G: Operational Flexibility for DER Providing ISO Grid Services

Business Case G (see Section 8.5.8.5 for more details) addresses grid services that could be provided by DER to the bulk power system. Although most DER are relatively small (less than1 MW), in aggregate they can either negatively or positively impact the reliability, performance, and efficiency of the bulk power system. Grid services that could be provided by DER include energy and ancillary services. These services could be mandatory (if so regulated), contractual, or market-driven through price signals or direct market participation, with different jurisdictions determining different requirements. In this context, grid services provided by DER can include both generation and load-related services, as well as frequency, voltage, and contingency support.

The CAISO recognizes the value of DER integration and has actively worked with stakeholders to create opportunities for DER to provide grid services through load curtailment, load shift, and export of energy. The CAISO also believes that DER can provide value through grid informed retail rates that incentivize consumption that aligns to system grid conditions without participating directly in the CAISO markets.

The DSOs will have to determine whether any service potentially being provided to CAISO might negatively affect the distribution system and to take actions to minimize any such impacts. One method would entail using the operational flexibility provided by the firm limits and non-firm capacities of neighboring DER systems to counteract any negative effects (compensation may be warranted).

It is important to recognize that Business Case G can benefit from aggregations of DER facilities, community microgrids, fleets of EVs, and Virtual Power Plants (VPPs) that support the operational flexibility Use Cases described as supporting Business Cases A, B, C, E, and F, since these would likely be required for DER providing grid services to the ISO either through the markets or through requirements or operational control.

3.3.9 Priority of Business Cases

Of these Business Cases, the first three, Business Cases A, B, and C, focused on managing power exports and imports at DER facilities, thus affecting the capacity of circuits and possible congestion or thermal overload conditions. They were deemed high priority and received the most discussion by the SIOWG.

Business Case D was not seen as high priority since the DSOs believed they could handle any voltage problems with their existing voltage support equipment and Rule 21 Tariff volt/var capabilities (*this conclusion may need to be revisited at a later date since voltage support may need to become more granular in space and time*).

Business Case E was deemed high priority although there was some overlap with the first three Business Cases. EVs, however, raise issues which are not addressed in the other Business Cases, so Business Case E remained separate and was reviewed by EV integration experts.

Business Case F was deemed high priority for community microgrids, namely those that include part of the distribution system between multiple customers. Behind-the-meter (BTM) single customer microgrids were deemed out of scope since they do not include any distribution system equipment.

Business Case G was provided to CAISO for review and comment. CAISO identified their high priority capabilities.

3.4 Allocation of Use Cases to Business Cases

3.4.1 Prioritization of Use Cases

Use Cases are the technical methods for supporting the Business Cases. The Scoping Memo required the Use Cases to be prioritized, using criteria based on the benefits to different stakeholders. It was recognized that some benefits could be financial or other type of incentive, but quantification of these types of benefits was excluded from the scope of the SIOWG. Therefore, prioritization was based on subjective views on the stakeholder benefits and the probable timeliness of the necessary technologies.

Initially, many Use Cases were identified from various sources, including SIWG reports and input from SIOWG participants.

A Prioritization spreadsheet was developed with all the Use Cases organized by Business Case. A set of priorities was defined for participants to select. Participants were asked to identify their priority assessment for each of the Use Cases, along with the Values to different stakeholders which made them high priority. SCE, PG&E, SDG&E, 350BA, CALSSA, and CAISO (for ISO Use Cases) evaluated most of the Use Cases. Some other participants evaluated specific Use Cases. Since only the high priority use cases would be more fully assessed, neither medium nor low priorities included timeframes for availability of the technology.

The priorities to select from in the Prioritization spreadsheet included:

- High Priority: Technology already available
- High Priority: Technology should/could become available in near-term
- High Priority: even though technology only available in long-term (greater than 5 to 10 years)
- High Priority: Important, but only for unique situations or sizes

- Medium: Important, but not high priority at this time (timeframes not included)
- Low: Not a high priority at this time (timeframes not included)
- Other: (fill in)

In addition to the priorities, participants could select from the values to different stakeholders, as shown in Table 1. This process was established both to simplify the process for participants as well as to result in more consistent responses with respect to these stakeholder values.

Table 1: Values to different stakeholders

Value to DSO	**Value to Aggregator**	**Value to DER Owner**	**Value to Ratepayer and Society**
Safety to minimize personnel harm	Increasing capacity available for interconnecting additional DER	Increasing capacity available for interconnecting additional DER	Increasing capacity for interconnecting DER
Reliability to minimize power outages and equipment damage	Avoid paying for distribution upgrades	Avoid paying for distribution upgrades	Deferral of distribution upgrades paid by DSOs using DERs
Efficiency to minimize unnecessary utility operational costs	Increased flexibility in managing DER and loads within constraints	Increased flexibility in managing DER and loads within constraints	Increasing reliability via microgrids or other grid changes
Flexibility to meet reliability and efficiency goals through timely response to situations	Increased revenue by taking advantage of more granular and/or relaxed constraints/limits	Minimizing the frequency and/or the duration of outages (CAIFI/SAIFI, CAIDI/SAIDI)	Minimizing the frequency and/or the duration of outages (CAIFI/SAIFI, CAIDI/SAIDI)
Increased capacity to meet renewable energy goals	Improved ability to respond autonomously to grid conditions	Lowering their cost of energy	Lowering the cost of energy
Defer utility construction costs (actually ratepayers benefit unless performance-based)	Improved ability to plan based on timely utility changes to limits	Increased revenue by taking advantage of more granular and/or relaxed constraints/limits	Equalizing the cost of energy across all types and locations of customers
Demonstrable progress (capacity, flexibility, reliability) toward meeting SB 100 for 100% renewable by 2045	Providing distribution services to DSO through management of DER, including load and EVs	Improved ability to respond autonomously to grid conditions	Increasing the ability to implement community microgrids to reduce the cost of energy
Technology is readily available for implementation in the near-term	Providing ancillary services to CAISO	Improved ability to plan based on timely utility changes to limits	Increasing the ability to charge electric vehicles at desired charging rates
Other: (*fill in)*	Increased ease/lower costs for the Interconnection Process	Providing distribution services to DSO through management of DER, including load and EVs	Reducing emissions through reduced use of fossil fuels
	Avoid paying for upgrades	Providing ancillary services to CAISO	Increasing capacity for interconnecting DER

Value to DSO	Value to Aggregator	Value to DER Owner	Value to Ratepayer and Society
	Other: (*fill in)*	Increased ease/lower costs for the Interconnection Process	Progress toward meeting SB 100 for 100% renewable by 2045
		Minimizing facility costs	Other: (*fill in)*
		Other: (*fill in)*	

This prioritization process took some time as Use Case descriptions were refined, and different understandings of the priorities were clarified.

3.4.2 Down-Selecting of Use Cases by Priority

After the process of describing, clarifying, and organizing the Use Cases (see Annex C), the SIOWG participants prioritized them. The Use Cases related to the export and import of power were deemed High Priority although variations in implementation timing and benefits were noted. The few Use Cases related to voltage management were rated as Medium or Low priority. The EV Use Cases, the Community Microgrid Use Cases, and the CAISO Use Cases were also prioritized and down-selected to only a few key Use Cases. These High Priority Use Cases were then organized by the Business Cases they could support.

All Use Cases that were indicated as High Priority by at least one participant were allocated to the corresponding Business Cases. In subsequent iterations, some of these Use Cases were re-evaluated as *not* High Priority (see the detailed Business Case descriptions in Sections 4, 6, 7, 8, and 9 for more details). The following is the allocation of the high priority Use Cases to Business Cases – as can be seen, some Use Cases were allocated to multiple Business Cases.

- Business Cases A (Include in Interconnection Agreement and/or Limited Load Profile), B (Abnormal Grid Conditions), C (Distribution Services): Operational Flexibility with Firm Limits and Non-Firm Capacity
  - Use Case (A,B,C)1. Scheduled Maximum Export Limit
  - Use Case (A,B,C)2. Commanded Maximum Export Limit
  - Use Case (A,B,C)3. Generation Minimum Export Requirement
  - Use Case (A,B,C)4. Import Limits (Scheduled, Commanded, Minimum)
  - Use Case (A,B,C)5. Situational Awareness (eventually included as technical requirements in each Use Case)
- Business Case D: Maintain Voltage Levels via DER
  - Use Case D1: DSO establishes enhanced volt/var settings and/or issues command to update volt/var settings
  - Use Case D2: DSO establishes enhanced volt/watt settings and/or issues command to update volt/watt settings
- Business Case E: Electric Vehicles Provide Distribution Services
  - Use Case E1: EV Peak Power Limiting (Demand Response or Limiting Import)
  - Use Case E4: Volt-Watt Response by EVs
  - Use Case E8: Coordinated Charge/ Discharge of EVs to Ensure Desired State of Charge is Reached at the Requested Time
  - Use Case E9: V2G EV as DER (Meeting Rule 21 Tariff requirements)

- Use Case E12: Watt-Var function
- Use Case E15: Limit Active Power Export function

- Business Case F: Microgrid Management for Grid Support
  - Use Case F1: Energy Arbitrage
  - Use Case F2: Microgrid Island Formation
  - Use Case F3: Microgrid Management for Grid Services
  - Use Case F4: Islanded Microgrid Backup Power or Off-Grid Power
- Business Case G: Provide ISO Ancillary Services (For use by CAISO)
  - Use Case G4: Operating Reserve (Spinning Reserve)
  - Use Case G16: Default Settings and Actions if Communications are interrupted
  - Use Case G17: Unintentional Islanding
  - Use Case G18: Black Start
  - Use Case G19: Anti-Duck Curve Scheduled Dispatch
  - Use Case G20: Anti-Duck Curve Dynamic Dispatch
  - Use Case G21: Scheduled Capacity
  - Use Case G22: Dynamic Demand Response
  - Use Case G23: Dynamic Shift Shimmy

It should also be noted that the working group meetings and this report do not provide a full assessment of different technologies. References to technology being available and potentially able to meet the requirements of the use cases are based on conceptual understandings and, in most cases, not on actual experience.

Further, although the report tries to identify potential benefits associated with the use cases, it does not examine the potential ratepayer cost that will be incurred to implement each of the use cases. It does not consider the additional personnel and technology resource requirements from the DSOs to support the increased coordination, analysis, management and operation of the DERs. These additional resource requirements may vary depending on the degree to which third parties (e.g., aggregators) perform some of the functions.

3.4.3 Matrix of Business Cases A, B, & C and their Use Cases

Often different Use Cases can help meet the same Business Case, and conversely, the same Use Case can help meet different Business Cases. Therefore, both Business Cases and their associated Use Cases are necessary to describe the assessments of the SIOWG.

A very clear case in point are the 3 Business Cases A, B, and C which have different goals, but which rely on very similar Use Cases to achieve those different goals. For this reason, those Business Cases are described separately, but some of the associated Use Cases are combined to avoid unnecessary duplication. In addition, the fifth Use Case, Situational Awareness, was applicable to all the other Use Cases, and was therefore incorporated into the technical descriptions of those Use Cases.

Specifically, Business Cases A, B, and C are described in Section 4, while the Use Cases for those Business Cases are described in Section 4.3.4.5 (Export Use Cases) and Section 6 (Import Use Case).

Table 2 shows the matrix of Business Cases A, B, & C to their Use Cases. The limits and requirements in this table would be set by the appropriate DSO.

Table 2: Matrix of Business Cases A, B, & C to Export and Import Use Cases

Use Cases / Business Cases	Use Case 1. Scheduled Maximum Export Limit	Use Case 2. Commanded Maximum Export Limit	Use Case 3. Generation Minimum Export Requirement	Use Case 4. Import Limits (Scheduled, Commanded, Minimum)
Business Case A: Operational Flexibility in DER Interconnection or Limited Load Profiles	**Use Case A1:** Inclusion of Firm Export Limits and Non-Firm Export capacity for scheduling maximum export limits in Interconnection Agreements	**Use Case A2:** Inclusion of Firm Export Limits and Non-Firm Export capacity for commanding maximum export limits in Interconnection Agreements	**Use Case A3**. Generation Export Minimum Requirement in Interconnection Agreements	**Use Case A4:** Firm Import Limits and Non-Firm Import (Load) Capacity in Limited Load Profiles
Business Case B: Operational Flexibility during Abnormal Conditions	**Use Case B1:** Scheduled Firm Export Limits and Non-Firm Export Capacity Before or During Abnormal Conditions	**Use Case B2:** Commanded Firm Export Limits and Non-Firm Export Capacity for Abnormal Conditions	**Use Case B3:** Minimum Generation Export Requirement for Abnormal Conditions	**Use Case B4:** Firm Import Limits and Non-Firm Import (Load) Capacity Before or During Abnormal Conditions
Business Case C: Operational Flexibility for Distribution Services under Normal Conditions	**Use Case C1:** Scheduled Firm Export Limits and Non-Firm Export Capacity for Distribution Services	**Use Case C2:** Commanded Firm Export Limits and Non-Firm Export Capacity for Distribution Services	**Use Case C3**: Minimum Generation Export Requirement for Distribution Services	**Use Case C4:** Firm and Non-Firm Import (Load) Limits for Distribution Services

3.5 Overview of SIOWG Participant Consensus, Non-Consensus, and/or Qualifications

3.5.1 Overview of Consensus on Business Cases A, B, C, E, and G

The SIOWG members worked very hard to come to consensus on how the SIOWG scope and the emphasis on operational flexibility could be met. Ultimately, there was general consensus on the concepts of operational flexibility in the High DER Future for Business Cases A, B, C, E, F, and G. Consensus statements were provided by:

- SCE
- PG&E
- SDG&E
- CAISO
- Enphase
- IREC

Business Cases A, B, and C, Operational Flexibility: All companies providing consensus statements supporting the operational flexibility of optionally including firm export and/or import limits plus non-firm export and/or import capacity in the Interconnection Agreements and/or Limited Load Profiles. The use of the non-firm export and/or import capacity would require authorization by the DSO. The primary qualifications included:

- The DSO had developed, tested, and implemented ADMS, DERMS, and other necessary systems to support this operational flexibility.

- The participating DER systems supported real-time or near-real-time communications with the DSO either directly or through an aggregator.
- The DSO would have absolute say on authorizing non-firm capacity and would still have the ability to curtail DER systems below the firm limits during abnormal conditions for safety and reliability purposes.
- Appropriate and fair tariffs would need to be developed for this operational flexibility.
- On Business Case C, the DSOs had additional qualifications on the meaning of the term “distribution service”, in which they believe only services that benefit the grid should be called distribution services. This concern was used to distinguish between “DSO services”, “Community services”, “Ratepayer services”, CAISO services”, “Aggregator and DER Owner services”, and “Societal services”. These different services were then expanded to discuss which stakeholders might benefit from each type of service.

Business Case E, Electric Vehicles: The SIOWG participants, while still supporting the Business Case, expressed the opinion that from their perspective, the capabilities described for managing the charging and discharging of electric vehicles as DER (EV-as-DER) were addressed in Business Cases A, B, and C (importing and exporting). This was due to the fact that EVs while discharging are already subject to Rule 21, as well as the fact that importing (charging) would now be considered as one aspect of operational flexibility.

Business Case F, Community Microgrids: Microgrids were initially deemed as *not within* the CPUC jurisdiction when islanded and identical to any virtual power plant when connected to the grid. However, it was later determined that “community microgrids” *were within* the CPUC’s jurisdiction, namely microgrids that consisted of more than one customer and therefore included parts of the DSO grid (wires and transformers) would still require DSO oversight of the microgrid’s use of those assets. Unfortunately, because of this misunderstanding, no consensus/non-consensus comments were received other than SCE's view that this business case should be addressed in the CPUC's microgrid proceeding.

Business Case G, ISO Grid Services: The DSOs supported the concepts in this business case but added that the primary need is to continue to manage the distribution-transmission interfaces when DER are providing grid services to the ISO. Otherwise, these services are the purview of CAISO. CAISO states that the ISO will continue to support the development of DER integration including improved visibility for grid reliability, as well as pathways for their participation in wholesale markets providing grid supporting services. Pathways for continued efforts in this area include state level proceedings, collaboration with FERC, and ISO stakeholder initiatives for DER policy development.

The detailed consensus, non-consensus, and qualifications can be found in the sections addressing each Business Case and Use Case. A summary is provided in Annex D.

3.5.2 Overview of Consensus on Business Case D

The consensus on Business Case D was that it was not high priority at this time and therefore did not need to be addressed in the SIOWG. No other comments were received.

3.6 Overview of Possible CPUC Actions

For the High DER Future, the following issues were identified related to possible CPUC actions:

- Some proposed CPUC actions could take place in the nearer term, such as for Use Case 1 on scheduling of export limits, while others will require longer terms since they involve new concepts and types of regulations, such as Use Case 4 (Import (Load) Limiting).
- The timeframes for requiring the proposed CPUC actions will necessarily reflect the state of the DSO ADMS/DERMS and the DSO communication capabilities, as well as time for DER testing.

- Since most of the requirements are expected to take effect at the DER facility point of common coupling to the DSO's grid, new testing procedures will need to be developed that not only require testing and certification of individual DER units but also entire facilities at their PCC.
- It is expected that the DSO ADMS/DERMS will have capabilities for assessing short-term forecasts of the distribution grid, such as day-ahead or week-ahead, with hour-ahead possible for some situations or locations.
- It is expected that the DSOs will be capable of using AMI data, telemetry where available, and/or aggregator data as input to these short-term distribution grid forecasts. This implies the need to develop contractual requirements between DSOs and aggregators.
- Although not explicitly captured in this SIOWG process, it is expected that the DSO scheduling, commands, and communications capabilities will also be utilized for other functions, as may be identified in Rule 21 Tariff, IEEE Std 1547-2018, and revisions to IEEE Std 1547, including V1G and V2G.
- It may be that the CPUC treats the “Export” and “Import” requirements in a combined proceeding since distributed energy resources are often combinations of generation and consumption (discharging and charging). If so, that may change the detailed CPUC actions described in the subsequent subsections.
- While coordination may be assumed, the CPUC will need to work in collaboration with other entities including CEC, CAISO, UL (for safety testing), and others.

4 Business Cases A, B, and C: Operational Flexibility with Active Power

4.1 Business Case A: Operational Flexibility in DER Interconnection Agreements or Limited Load Profiles

4.1.1 Business Case A: Description

Business Case A envisions the High DER Future to include flexibility in Interconnection Agreements related to export limits and flexibility in Limited Load Profiles for import limits. Export limits currently are fixed when the Interconnection Agreement is signed, whether they are an implicit limit based on the DER capacity, a single explicit limit included in the agreement, or a set of scheduled limits determined by the DSO for safety and/or reliability purposes, such as the Limited Generation Profile (LGP) effort.

Export Limits. The envisioned flexibility would require Interconnection Agreements to include firm export limits, but could, optionally, include additional non-firm export capacity. The DER operator could only use this non-firm capacity if the DSO authorized it: the DSO would assess the grid capacity for the (electrical) location of the DER facility and, if more capacity was available, would then authorize the DER operator to utilize some or all of this extra non-firm export capacity during specific time periods (hours, days, days-of-the-week, weeks, months) as “operational limits”.

Figure 10 provides a conceptual example of export limit flexibility. As shown below, the blue bars represent the firm export limit set within the Interconnection Agreement while the orange bars represent the non-firm capacity that can be authorized by the DER operator. While the example in Figure 10 shows a static amount of firm export and additional capacity export over the course of a year, Figure 11 details a dynamic conceptual example by combining the firm export limits with non-firm export capacity into a Limited Generation Profile (LGP). This example demonstrates the fluctuation in both firm export limits and non-firm export capacity over time.

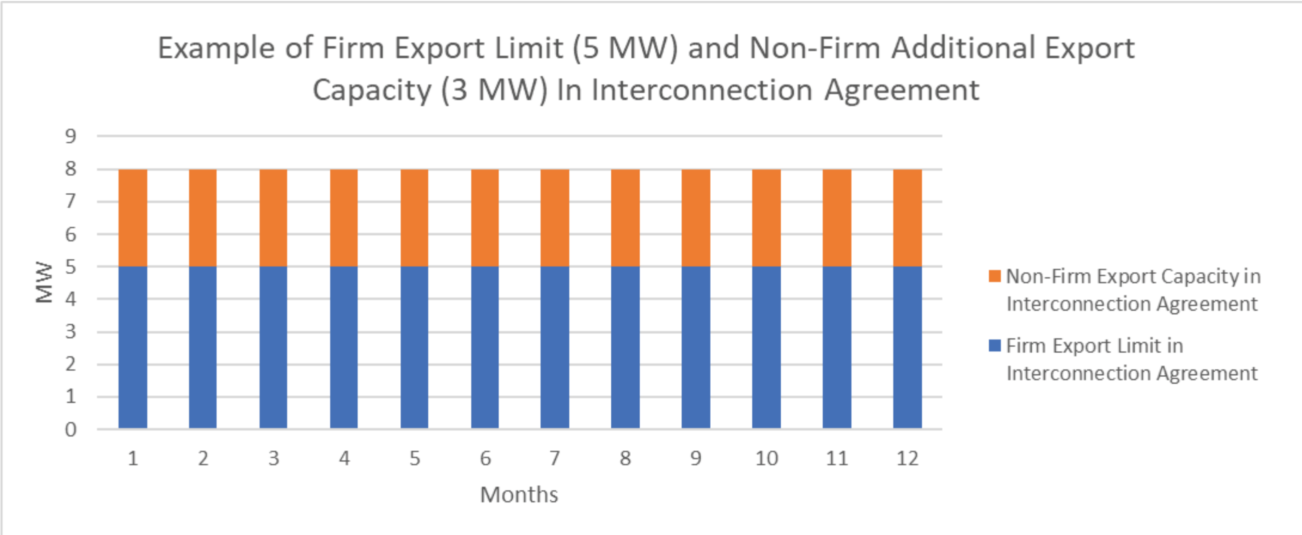

Figure 10: Example of Firm Export Limits and Additional Non-Firm Capacity in Interconnection Agreement

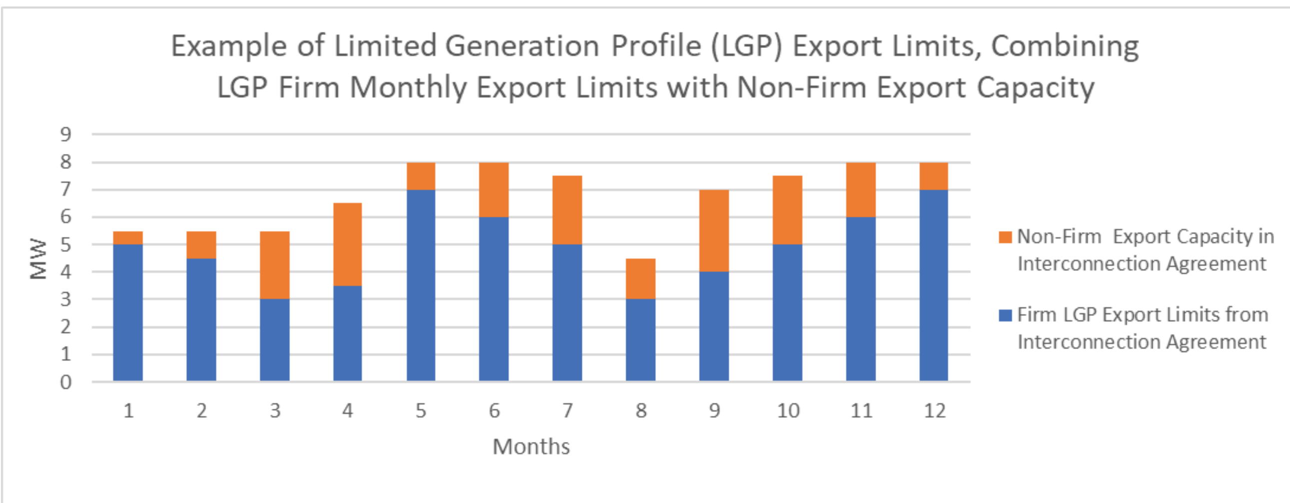

Figure 11: Example of a Limited Generation Profile with Firm Export Limits and Additional Non-Firm Capacity in Interconnection Agreement

Import Limits. At this time, import limits are largely not present given the utilities' obligation to serve their customers.[22] Electric rules and service agreements do not include a formal Limited Load Profile except to give the DSO time to implement any necessary upgrades to the distribution system in the context of Rule 21. That may change as more electric vehicles charge from the grid.

Operational flexibility could also extend *optionally* to import limits by including firm import limits (possibly per scheduled times as is currently possible for export limits) as well as additional non-firm import capacity that could be used if authorized by the DSO in Limited Load Profiles. This approach might be used to avoid, minimize, or defer distribution system upgrades, whether paid for by the DER owner or by ratepayers. An example of a Limited Load Profile containing firm import limits and non-firm import capacity is shown in Figure 12.

[22] *in California, section 451 of the Public Utilities Code articulates energy utilities' "obligation to serve" their customers, requiring that they "furnish and maintain... adequate, efficient, just, and reasonable service" for customers in their service territories.*

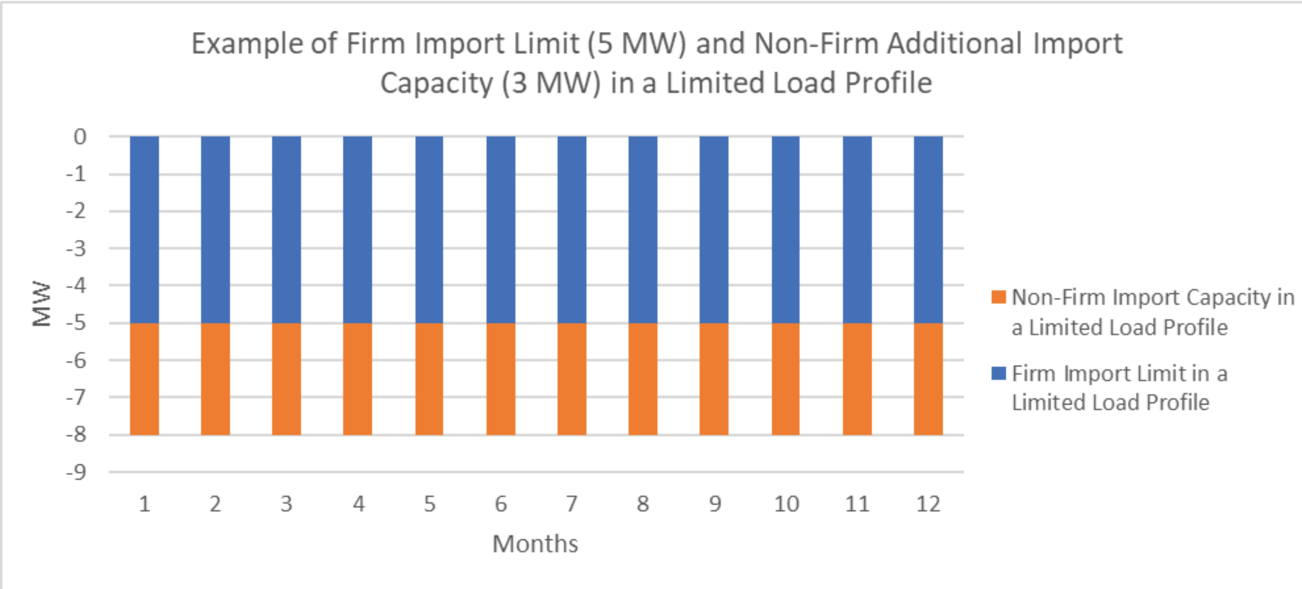

Figure 12: Example of Firm Import Limits and Non-Firm Import Capacity in Limited Load Profile

Another example in Figure 13 shows how firm import limits and non-firm import capacity could vary by month.

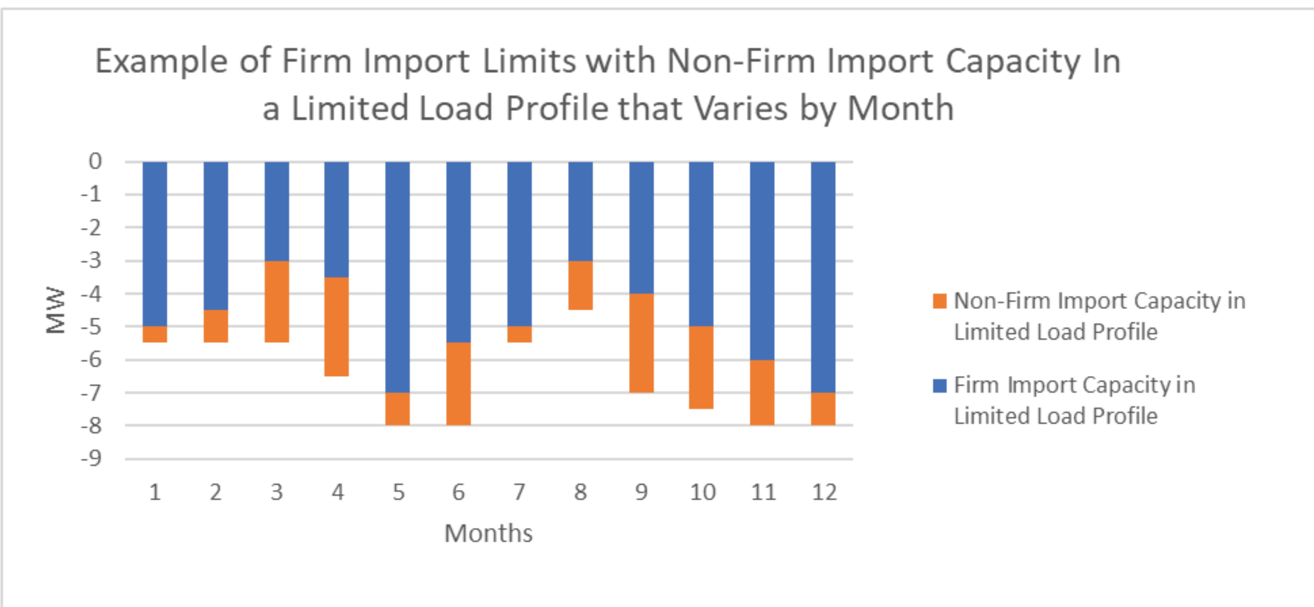

Figure 13: Example of Firm Import Limits and Non-Firm Import Capacity Varying by Month

Although incentives and/or compensation are out-of-scope for the SIOWG, it may be that this shift in managing the export and/or import of power could involve such compensation, or other incentives such as grid informed retail rates which incentivize DER on when to increase or decrease imports or exports.

4.1.2 Business Case A: Purpose to Solve Problems or Provide Opportunities for Different Stakeholders

The purpose of Business Case A is to provide an *optional* contractual basis to minimize costs to DER owners and to ratepayers as well as to benefit society. This contractual basis incorporates in the DER Interconnection Agreements or Limited Load Profiles firm scheduled export and/or import limits and non-firm additional export and/or import capacity. This contractual flexibility will benefit many stakeholders:

- **Benefit the DSOs** by providing DER systems with a greater ability to support grid safety and reliability, and to help manage distribution circuit congestion through flexibility in establishing export and import limits.
- **Benefit ratepayers by minimizing or deferring distribution system upgrades by the DSO** through ***optionally*** establishing firm scheduled export and/or import limits while still including additional non-firm export and/or import capacity in DER Interconnection and/or Limited Load Profiles.
- **Benefit DER owners by minimizing or deferring what, if anything, they need to pay for distribution system upgrades,** through ***optionally*** establishing scheduled firm export and/or import limits and including additional non-firm export and/or import capacity in the Interconnection Agreements and/or Limited Load Profiles. These agreements would permit DER owners to take advantage of possible increased available capacity to export or import more power when use of the non-firm capacity was authorized by the DSO.
- **Benefit society and meet California's renewable energy goals through maximizing existing capacity usage** of interconnected DER by utilizing both scheduled firm export and/or import limits and by allocating additional non-firm capacity to operational DER, based on more timely and granular information regarding grid capacity availability from ADMS/DERMS analyses. This flexibility to manage exports and imports more dynamically could also help California meet its carbon neutrality goals by allowing more capacity to be used in the distribution system.

4.1.3 Business Case A: Justifications and Benefits for Stakeholders for Business Case A

4.1.3.1 Overview of Benefits

Business Case A benefits ratepayers, DER owners, and society by allowing Interconnection Agreements and/or Limited Load Profiles to provide both firm and non-firm export and/or import limits in order to maximize use of existing capacity and minimize unused capacity, as discussed in the next sections. Table 3 provides an overview of justifications and benefits for stakeholders for Business Case A.

Table 3: Justification and Benefits for Stakeholders for Business Case A

Business Case A Justifications and Benefits	Description of Specific Justifications and Benefits
DSO benefit: Safety and Reliability	Since these optional Interconnection Agreements and/or Limited Load Profiles are flexible, the DSO can modify export and/or import limits periodically within the pre-specified range for specific DER sites to reflect new safety and reliability studies for normal conditions, as well as abnormal conditions, so long as these modifications remain within the accepted range of limits.
DSO benefit: Defer or avoid grid upgrades due to unused export and/or import limits.	Over the long term, DSOs can defer or avoid the cost of upgrades on specific circuits if some unused capacity can be allocated to DERs with capabilities to provide grid support
DSO benefit: Fewer controversies over fixed limits	Although there will always be controversial decisions, with flexible limits that may be modified over time to reflect more accurate and more timely data, the controversies over these limits will decrease.

Business Case A Justifications and Benefits	Description of Specific Justifications and Benefits
DSO benefit: Capability to provide unused capacity to other DER sites	If certain DER sites do not use their allotted export and/or import capacity over a specified period, that capacity can be re-allocated to other DER systems or used to defer construction.
Existing DER owner/operator benefit: Potential additional revenues due to modified export and/or import limits	The limits specified by the DSO are necessarily conservative due to the lack of granular information and control. They could likely become less stringent as more granular and timely data is available. DER owners could increase their revenues if the schedules of export and/or import limits are made less stringent. This is particularly true if only certain times (hours, days, months) have stringent limits while other times have less stringent limits.
Existing DER owner/operator benefit: With more flexible limits, provide more energy services	The DER site could provide more energy services if some of the use of export and/or import non-firm capacity were authorized by the DSO..
Ratepayer benefit: Efficient use of capacity to defer or avoid rate base costs	Ratepayers would benefit from the interconnection or load capacity being more efficiently used by allowing the DSOs to defer or avoid construction of upgrades that would be part of the rate base. Unused capacity could be allocated to other ratepayers and that capacity would not be left as "blocked".
Societal benefit: Efficient use of capacity to permit more interconnections of renewable energy	Society would benefit from more efficient use of capacity to permit more renewable energy sources, while minimizing the cost of expanding capacity, either through deferral of capacity upgrades or through use of DERs to use the existing capacity more effectively and efficiently. Deferral of capacity upgrades and/or DERs increasing efficiency of existing capacity usage could permit more renewable energy sources while decreasing the cost of expanding capacity. There may be a disbenefit to society to the extent that allocating "under-utilized" distribution capacity to existing DER owners/operators creates a barrier to entry for new, potentially more efficient, DERs. Rules for authorizing the use of non-firm capacity will need to be carefully balanced across all stakeholders.

4.1.3.2 Benefit to Ratepayers

DSOs have an obligation to serve their customers safely and reliably, but at the same time need to minimize the costs to their ratepayers where they can. One key way that DSOs can accomplish minimizing costs is to avoid or defer upgrades to their distribution systems. To assess if an upgrade is necessary, DSOs leverage historical load data paired with forecasts for future generation and load needs. Utilizing the combination of historical load data with forecasts is necessary because of the lack of accurate, multi-year grid constraint data, but the resulting analyses tend to be conservative and indicate a greater need for grid upgrades or lack of available capacity. The reason that the assessments are conversative also reflects the realistic state of data granularity and forecast accuracy.

It may be that the more granular level an analysis is performed, the greater the likelihood of incorrect estimations of specific load profiles, due to incomplete or imperfect data. For example, one customer's different usage pattern could impact loading of the service transformer more significantly than represented by an "averaged loading" of the circuit. Therefore, DSOs "pad" the granular results to compensate for variabilities in data and real-time changes from predicted values.

With the increase in electric vehicle charging, electric heating, fixed storage charging/discharging, and weather-sensitive solar generation, analyses using only historical conditions without taking the new developments into account, have become less accurate in predicting the future grid conditions. If Interconnection Agreements and/or Limited Load Profiles include only firm export and/or import limits, these inaccuracies, particularly over the years, could cause significant amounts of capacity to remain unused.

DSOs are developing ADMS/DERMS systems to study and improve that accuracy, such that it will become clearer where more capacity may be available during different time periods before distribution upgrades are needed. Therefore, if firm capacity limits (import and export) can be managed through schedules to take advantage of that capacity, then distribution upgrades can be minimized or deferred. In addition, if non-firm export and/or import capacity can be included in contractual agreements, then even more capacity could potentially be utilized, possibly resulting in distribution upgrades being even further deferred or even avoided if non-wires solutions can be utilized.

In addition, with increased communications capabilities with DER and aggregators, DSOs would have the ability to issue control commands, particularly during or in expectation of abnormal grid conditions. Flexibility would entail identifying the types of commands (to limit export, to limit import, to provide additional exported generation (if possible), to provide additional import (if possible), microgrid islanding capabilities, etc.) that might be applicable. These would become the "*operational limits*" for the duration of the abnormal grid conditions. More transparency on these future command requirements could also benefit customer acceptance with fewer negative reactions if DSO explanations are clear and justifiable for these actions.

4.1.3.3 Benefit to DER Owners and Aggregators

DER owners (including DSO owners of DER systems) will also benefit from minimized or deferred distribution system upgrades. Schedules of firm limits that are within the estimated circuit capacity may decrease the need to pay for system upgrades, while still providing the ability to take advantage of non-firm export and/or import capacities authorized by the DSO as *operational limits* for specific time periods.

This flexibility in interconnection will become more critical in the future as more and more DER implementations, including generation sources and controllable loads, are installed throughout the grid, thus profoundly affecting the dynamics of distribution grids. This means that export or import limits calculated today may not be the actual limits needed next week or next year – those limits may be more stringent or less stringent. In the High DER Future, near-real-time communications, ADMS/DERMS assessment capabilities, and planning tools are expected to become available and will be crucial to managing these dynamically changing grid conditions. The Interconnection Agreements and/or Limited Load Profiles will need the flexibility to support these changing situations, so long as they provide flexibility that allows the DER operators to manage their expectations and thus plan for and work within the authorized operational limits. An example is a modification of Limited Generation Profile (LGP) which combines a schedule of firm limits with authorized non-firm capacity (see Figure 14).

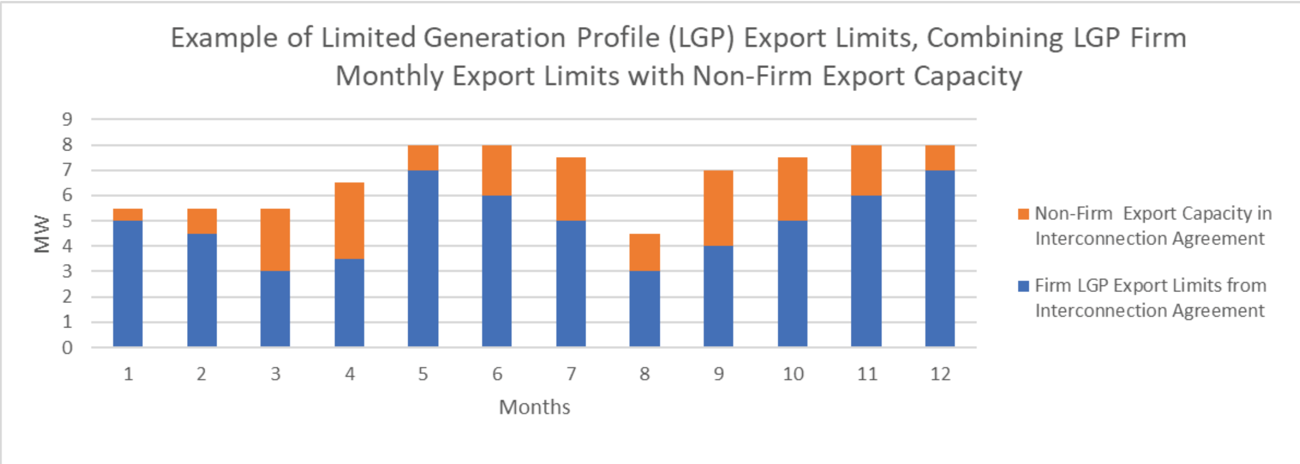

Figure 14: Example of Scheduled Operational Limits Combining LGP Firm Limits with Authorized Non-Firm Capacity

4.1.3.4 Benefit to Society and California Renewable Energy Goals

In the High DER Future, near-real-time communications (< 5 minutes interactions) and power assessment applications in ADMS/DERMS system will help maximize capacity usage by supporting more granular constraints: either by allowing more power export or import when that is actually available or by constraining export or import just during the necessary timeframes. The ability to modify schedules or even command changes to permit additional non-firm export and/or import capacities via near-real-time communications would be part of the flexibility in the Interconnection Agreements and/or Limited Load Profiles.

Effective use of capacity will be improved by operational flexibility if the DSO determines not only whether a DER facility could use the extra capacity but actually does use it. If DER operators could provide forecasts of their desired export or import operational limits, the DSO could more accurately authorize the extra capacity to those DER who can use it. This could be managed in a similar manner to deficiency billing for load projects where if customers don't meet the load allowance they projected after a certain number of years they may be billed for the shortfall.

4.1.3.5 Examples of Flexibility in Interconnection Agreements and/or Limited Load Profiles

As examples, flexibility in these non-firm export and/or import capacities in DER Interconnection Agreements and/or Limited Load Profiles could include one or more of the following:

- **Flexibility for scheduled *non-firm* export and/or import capacity.** If Interconnections Agreements or Limited Load Profiles can include the ability to update schedules to include permissions to export and/or import some of the non-firm capacity, then these schedules could allow customers to take advantage of these updated export and/or import limits by shifting some of their generation and/or controllable loads.
- **Flexibility for supporting DSO control commands for modifying *firm* export and import limits, specifically for short term (a few hours to a few weeks) abnormal conditions**. Although the capability to issue control commands is included in Rule 21 Tariff and DSOs have the ability to curtail export or import power for grid reliability and safety, currently this capability is not available through automation since there are no DSO communications with the smaller DER (< 1 MW). In addition, only one-way telemetry for monitoring is available for most of the larger DER. This often results in the DER facility being required to completely stop exporting or importing, even if that were not necessary or even when it is detrimental to grid safety (e.g., causing overloads of other circuits).

If communications were available in the future High DER environment, this communications-enabled control capability could include contractual support provided by DER, possibly through their aggregators, to the DSOs. Therefore, the Interconnection Agreements and/or Limited Load Profiles could include the definition of "short term" and the range of firm limits covered by the control ability. The control commands could include:

  - Limit firm export to a pre-established value at a specific start time for a specific duration or until another command releases that limit. This pre-established value could be zero or a specific value determined during the evaluation of the abnormal condition.
  - Limit firm export to a value provided in the control command to be in effect at a specific start time and for a specified duration.
  - Limit firm import to a pre-established value at a specific start time for a specific duration or until another command releases that limit. This pre-established value could be zero or a specific value determined during the load evaluation of the abnormal condition.
  - Limit firm import to a value provided in the control command to be in effect at a specific start time and for a specified duration.
- **Flexibility for supporting DSO schedules and/or control commands for export and import *firm* limits for longer term (greater than a few weeks) abnormal conditions**, potentially involving compensation depending on the circumstances of the abnormal conditions. The Interconnection Agreement or Limited Load Profile would need to identify the maximum "longer term" duration and accumulated duration over a specified timeframe, which could be the duration for installing new substations, new circuits, upgraded wires, additional power system monitoring and control capabilities, etc. The methods could include:
  - Updated scheduled firm export or import limits for specific times periods
  - Control commands for changing firm limits and for restoring normal limits
- **Flexibility for more granular schedules of *non-firm* export and/or import capacities as a result of short-term studies and near-real-time data.** The schedules for *non-firm* export and/or import limits would be more granular (hourly, daily, day-of-week, etc.) and could be modified in week-ahead, day-ahead, or even hour-ahead timeframes to reflect current operating conditions. This flexibility would be included in the Interconnection Agreement and/or Limited Load Profiles.

- **Flexibility to access monitored data from Aggregators.** Although Rule 21 Tariff includes the capability to exchange information between the DSO and the DER, the smaller DER (< 1MW) have not been required to implement this capability. In many cases, aggregators do access key data from the DER they are responsible for, based on varying Limited Load Profiles.. For DSOs to have more accurate data on export and imports from these DER sites, the Interconnection Agreements or other Limited Load Profiles could include the ability to collect this key information in near-real-time through the aggregators. This ability would augment the AMI data already collected by the DSOs but often not available in near-real-time.

- **Flexibility to require near-real-time communications from DER facilities.** Situational awareness in near-real-time is becoming more critical for use by DSOs in their ADMS/DERMS to be able to assess safety and reliability conditions of the power system and to take appropriate actions if conditions are unsafe or unreliable. Without such near-real-time data provided by communications, the ADMS/DERMS capabilities will still be limited, regardless of the capabilities of their power flow studies and contingency analysis applications. This near-real-time data could be directly monitored or could be retrieved from aggregators. The flexibility in the Interconnection Agreements and/or Limited Load Profiles for specific DER facilities could take the form of requiring access to their pertinent aggregator data or could include the requirement for more direct communications in the future.

4.1.4 Business Case A: SIOWG Participant Consensus, Non-Consensus, and/or Qualifications

4.1.4.1 SCE Consensus, Non-Consensus, and/or Qualifications for Business Case A

SCE supports this concept with the following qualifications:

- The concept of flexible interconnections can only be implemented when SCE has developed, tested, and implemented all the systems (such as ADMS) needed to support DERMS communication, and orchestration of DERS in the grid.
- All DERs participating in this type of interconnection must be connected to SCE DERMs and must provide real-time (typically 3-5 second interval) or near real-time (typically 15-minute interval) communication as determined by SCE.
- DERs must agree, with no question to DSO, that the DERs will be curtailed down to the agree-on limit without advance notice as it will be part of SCE and its systems (DERMS) managing the grid.
- When required by SCE, due to unanticipated conditions, DERs may be required to disconnect or maintain a fixed limit until SCE has determined that limits may be updated.
- For operations related to support of the grid (such as capacity), the appropriate Power Purchase Agreements (PPAs) (or, for BTM DERs, customers Tariffs that must first be developed) must first be executed before these services can be provided.

4.1.4.2 PG&E Consensus, Non-Consensus, and/or Qualifications for Business Case A

PG&E supports the concept of having interconnection agreements that contain firm limits and non-firm capacity for import/export with the following qualifications:

- The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections.
- The DSO must have the planning tools available to determine reasonable firm and non-firm limits in advance for inclusion in the interconnection agreements.
- All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E.
- Backend IT systems will need to be updated for changes to the interconnection application system, interconnection agreements, application forms, and studies.
- Further definition is required of what is in the main interconnection agreement and what should be in an addendum or in the Distribution Interconnection Handbook (DIH) because each program has its own interconnection agreement (e.g., S-NEM, V-NEM, wholesaler, etc.), and a priority should be made to avoid unnecessarily complicating these agreements where addendums or the DIH may be better suited.
- All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO.
- The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios.
- The DSO does not offer a guarantee for the availability of any non-firm capacity.

- Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations.
- Not all distribution constraints may be able to be mitigated via a flexible interconnection.
- For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

4.1.4.3 SDG&E Consensus, Non-Consensus, and/or Qualifications for Business Case A

It is important that there be a clear understanding and use of "non-firm" limits. While there are significant potential benefits from using grid capacity that is available under certain conditions (e.g., when, near real-time, loads are expected to be higher than what was studied in an interconnection study), there may be significant disbenefits if this capacity were awarded to an existing generator on a permanent basis. Doing so could make it more difficult (costly) for new entrants with more efficient generation to interconnect to the grid and would constitute an unacceptable "barrier to entry." As long as the additional export capacity is treated as "non-firm," and therefore considered available to new entrants seeking to interconnect their generation, this disbenefit is avoided.

This business case will require new planning tools and procedures to evaluate the value proposition in specific cases. It will also require advances in communication infrastructure and related standards to facilitate the interoperability challenges between DSOs and the DER operators. Because of issues of maintaining high overall distribution system reliability and safety to workers and the public, the DSO's must have final control over the interconnection studies.

The modern DER system configuration is increasingly complex, even at residential household level. Customers, and even installers, may have limited or no understanding of how the communication system is configured. For example, for a battery plus storage system, is the system AC or DC coupled? If microinverters are utilized, is there a dedicated port available for communication, and if so, is it a serial or ethernet port? Is the system daisy chained or not? Is the total system output measured or estimated based on the main inverter? Answers to these configuration questions would have significant impact on whether the communication to, and the data access provided by these inverters, is accurate enough to support grid analysis, let alone accepting control/analog commands. The availability of ADMS/DERMS is just one piece of the architecture. More feasibility analysis, design, and configuration and testing would have to occur with support from inverter manufacturers and aggregators to implement the use cases within the business case. Support from DER owners and manufacturers is also essential so that additional validation steps can be built into the interconnection process to ensure the DER system level capability is actually in place and can be relied on for Business Cases A through C.

4.1.4.4 CAISO Consensus, Non-Consensus, and/or Qualifications for Business Case A

The ISO supports Business Case A so long as the IOU/DSO Non-Consensus and/or Qualifications are remedied.

4.1.4.5 Enphase Consensus, Non-Consensus, and/or Qualifications for Business Case A

In general, it looks very good, and Enphase supports the Business Cases.

4.1.4.6 IREC Consensus, Non-Consensus, and/or Qualifications for Business Case A

IREC envisions that close to "real-time" signaling and/or controls will be necessary to fully make use of the available time-varying hosting capacity on the distribution system. This leads to the concept of "flexible interconnection." Allowing for the use case of "firm export and/or import limits" plus optionally "non-firm export and/or import capacities" would benefit DER deployment and distribution system optimization. These non-firm limits could be authorized by the DSOs (via updated schedules, signals or even commands) when they determine in the near-term that there would not be impacts on the safety and reliability of the grid.

4.2 Business Case B: Operational Flexibility during Abnormal Conditions

4.2.1 Business Case B: Description

Business Case B addresses the DSO capabilities for providing information to DER operators before or during transitions to abnormal grid configurations. Abnormal conditions may often require mandatory DER operational restrictions or actions due to the grid becoming operationally different from its normal operating condition.

Business Case B focuses on the ***mandatory*** actions that DSOs require DER systems to take, such as reducing exports or imports during or in anticipation of abnormal conditions, while Business Case C involves ***voluntary*** actions initiated by DER operators due to an incentive (such as demand response), under normal conditions or even possibly as a voluntary response to potentially abnormal grid conditions such as a pending heat wave. The key difference is whether there are mandates or voluntary actions due to incentives. The results may be similar, but the regulatory aspects are different.

There are three possible situations where abnormal conditions may occur:

4. **Real-time localized emergency condition.** In this condition, an unanticipated emergency condition occurs without advanced warning (e.g., car hits pole). In this condition, the grid will need to be reconfigured to isolate the issue and restore power to customers. Due to the grid being reconfigured, DER operations may need to be modified quickly to prevent safety situations and/or to minimize performance impacts (e.g., voltage problems or outages).
5. **Planned grid maintenance condition.** In this condition, an anticipated temporary grid modification is planned in order to perform certain types of grid maintenance (e.g., replacement of power lines of other equipment). For these types of conditions, it may be possible to determine the DER modifications and to coordinate such modifications with the DER operator prior to the commencement of grid maintenance.
6. **Forecast system emergency conditions.** For these conditions, grid events such as the triggering of the Emergency Load Reduction Program (ELRP) (R.20-11-003) may require that DER operations, including dispatchable storage, be modified to support local load or grid needs more effectively for resource adequacy reasons during emergency conditions. This may include operations such charging storage systems ahead of an emergency or permitting the export of non-renewable power (e.g., from stationary energy storage systems or EV V2G).

DSOs have an obligation to serve their customers, and the grid has always been constructed conservatively to provide customers with the most safe and reliable grid performance for normal conditions. However, it would be infeasible and unnecessarily costly to construct the grid to cover all the many possible abnormal conditions. Operational procedures are designed to respond to these abnormal conditions as effectively and rapidly as possible, but these abnormal conditions can still impact grid customers, including DER systems. For instance, Rule 21 Tariff already includes provisions requiring DERs to cease operations or disconnect autonomously under abnormal conditions in which the voltage and/or frequency exceeds the voltage or frequency ride-through levels and times (voltage ride-through and frequency ride-through functions[23]).

However, in the High DER Future, it may be that DER operators could proactively take additional steps to minimize the impact of abnormal situations (e.g., planned or forecast conditions, as well as response to actual emergency conditions), particularly if there are resource adequacy issues, if the DSOs could provide information to them about the nature of the abnormal situation and issue commands (as schedules or direct control) to minimize impacts. Therefore, this business case addresses the DSO capabilities for providing such information

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[23] *Rule 21 Tariff section H.2.b.iii and Section H.2.f*

and commands to DER operators preferably before transitions to abnormal grid configurations and, when possible, even during emergency events.

In the High DER Future, when the DSOs have ADMS/DERMS assessment capabilities and can communicate with DER systems (via aggregators and/or Facility DER Energy Management Systems (FDERMS), the DER operators could be forewarned of pending abnormal conditions by DSO control commands or schedules. DER operators could voluntarily agree to permitting these communication interactions with the DSO about abnormal conditions if the scheduling and command infrastructure is already in place for grid services (see Business Cases A and C.)

These DER functionalities could also be used not only to forewarn the DER facilities but, if electrically and contractually possible, they could help support the grid during abnormal conditions to help meet resource adequacy needs by providing a specified minimum level of export or import power or by providing voltage support or even by providing frequency support. This DER support would be similar to that used in Business Case C, Distribution Services, where DSOs could use these DER operating capabilities during abnormal conditions, so long as resource adequacy could be assured. An example of scheduled flexibility during abnormal conditions is shown in Figure 15.

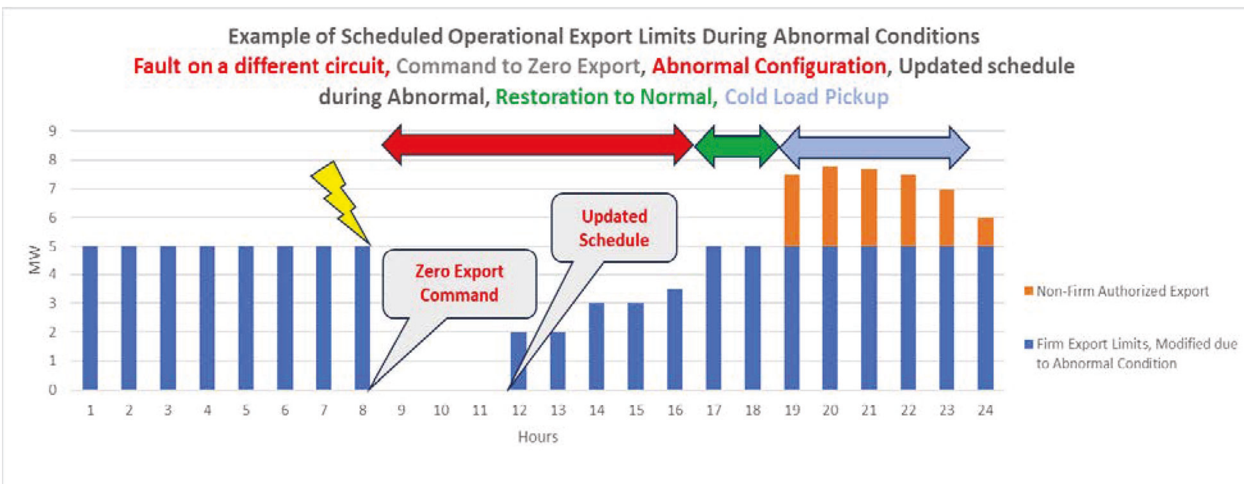

Figure 15: Example of Scheduled Operational Limits during Abnormal Conditions

Utilization of schedules to control export and import limits may be possible without the need for direct utility-to-DER communications. For instance, DSOs could prepare schedules for planned maintenance that could be downloaded manually. For DER sites with communications, schedules could be updated to reflect abnormal conditions related to planned maintenance or forecast emergency conditions.

In particular, given that abnormal conditions may always have unintended consequences, even if forecast, rapid communications between the DSO and affected DER facilities will be critical to utilizing the DER capabilities. Near-real-time communications (< 5 minutes interactions) for situational awareness was also considered high priority and could be used for communications between the DSO and the DER site for timely interactions to cope with planned or forecast abnormal conditions. Even the unplanned real-time emergency condition could be mitigated by providing commands or updated schedules in near-real-time so the DER customer could continue to operate safely. In some situations, it may be possible for basic communication capabilities to be invoked through aggregators.

For those DER operators without communication monitoring and control capabilities with the DSO, DER responses to these abnormal conditions might be manually invoked (e.g., by a phone call). Otherwise, many abnormal conditions would most likely result in tripping or cease-to-energize states, causing an outage of the DER facility.

For planned or forecast abnormal conditions more than a day ahead, the DSO could use Advanced Metering Infrastructure (AMI) metered data (while still ensuring privacy) for all customers in the affected circuits to help determine appropriate export and/or import power limits for DER on those affected circuits.

4.2.2 Business Case B: Purpose to Solve Problems or Provide Opportunities for Different Stakeholders

Addressing abnormal (planned or unplanned) conditions is essential to ensuring grid safety and reliability. The solutions to addressing these abnormal conditions also need to be appropriate to the situation and indeed, not cause additional problems. For instance, causing all EVs to stop charging due to a short-term voltage fluctuation could initiate cascading events that could cause unnecessary power outages.

Unplanned grid events can occur at any time (such as due to a car hitting a pole, due to unexpected weather events, or due to equipment failure). When such unplanned conditions occur, system protection devices can take quick action to isolate the fault (such as substation breaker opening to clear a line fault), followed by operator actions to locate the fault, isolate the fault, and restore power to customers. During these conditions, all DER on the affected circuits would be impacted and would try riding-through the grid condition, tripping off, or forming microgrids. However, in the High DER Future, DER systems could support additional actions by managing community microgrids, providing additional export of generation, and/or providing additional import.

For expected or forecast grid abnormal conditions (planned maintenance or forecast storm conditions), the DER system could be forewarned and could be provided with updated schedules or commands to allow them to better prepare. For instance, if possible, the DSO could change the import limits to allow faster charging of battery storage or EVs in preparation for lower limits during the abnormal condition. DER systems could also provide additional generation to meet local loads if the normal generation sources are limited or constrained and if resource adequacy can be confirmed. For example, during heat waves, the DSO could change the export limit conditions to allow BTM storage or EVs to discharge to the grid.

For some abnormal conditions, the DSO could ***require*** DER facilities to utilize their firm and/or their authorized non-firm capacity if the DER facility has committed to do so (via agreements or incentives).

4.2.3 Business Case B: Justifications and Benefits for Stakeholders

Business Case B benefits DSOs, DER owners, and ratepayers by limiting the risk of thermal overloads or exceeding voltage limits during abnormal grid configurations while maximizing the DER operational capabilities and making full use of existing grid hosting capacity to avoid unnecessary outages or performance problems.

Table 4 identifies justifications and benefits for stakeholders for Business Case B.

Table 4: Justifications and Benefits for Business Case B

Business Case B Justifications and Benefits	Description of Specific Justifications and Benefits
DSO benefit: Operational safety to minimize personnel harm and equipment damage	If DER operations are not adjusted based on grid conditions, the export and/or import of power may cause excessive power flows which can lead to thermal overloads or exceeding voltage limits. These conditions can harm equipment, leading to more failures and potentially cause safety issues. Being able to modify the DER exports and/or imports limits before or during these conditions can mitigate these operational safety and equipment damage concerns.

Business Case B Justifications and Benefits	Description of Specific Justifications and Benefits
DSO benefit: Operational flexibility to meet reliability and efficiency goals through timely response to situations	During reconfiguration and while the grid is in an abnormal configuration, the DSO could establish different export and/or import limits for the DER systems when possible, rather than trip the DER system. If resource adequacy (additional generation, additional load) can be provided by DER during abnormal conditions, then the DSO can benefit from scheduling or commanding such support.
DER owner benefit: Operational reliability to minimize power outages	If DER operators can be forewarned of planned or forecast abnormal conditions, or if additional non-firm export and/or import capacity can be authorized, these DER system may be able to better prepare for possible outages, such as increasing their stored energy in stationary batteries or EVs or preparing a microgrid to enter island mode.
DER owner benefit: Financial benefits	The DER owner could increase their revenue by taking advantage of more granular non-firm export and/or import capacities, particularly if near-real-time communications could update these export and/or import limits.
DER owner/operator benefit: Increased ease/lower costs for the Interconnection Process	With the ability to plan for limited export or import rather than just trip-off during emergency or planned maintenance conditions, DER owner/ operators could better adjust and optimize their operations. The ability to support grid operations during emergency conditions could further help avoid or defer grid upgrades.
Ratepayer benefit: Minimizing the frequency and/or the duration of outages (CAIFI/SAIFI, CAIDI/SAIDI)	Planning for non-wires solutions using DER systems could minimize the impact of abnormal conditions on customers and could help avoid or defer grid upgrades. Customers would also benefit from minimizing power outage numbers and durations and thus positively impact grid performance characteristics (CAIFI/SAIFI, CAIDI/SAIDI). If VPPs can respond autonomously to abnormal events by forming community microgrids, this might also minimize outages and help support underserved communities (see Business Case F).
Societal benefit: Maximizing the reliable use of DER capabilities under all grid conditions	If non-wires solutions using DER systems can be shown to respond reliably to grid conditions even during abnormal conditions, then DSOs could become more “comfortable” in permitting DER-based solutions to replace or at least delay the need for potentially costly distribution upgrades. Society would thus benefit as California works to reach its policy goals, including 100% renewable by 2045, lowering the cost of energy,

4.2.4 Business Case B: SIOWG Participant Consensus, Non-Consensus, and/or Qualifications

4.2.4.1 SCE Consensus, Non-Consensus, and/or Qualifications for Business Case B

SCE supports this concept with the following qualifications:

- On Table in Section 4.2.3 Strike the “societal Benefit” – See comments
- Grid abnormal conditions can have impacts on grid, employee, and public safety and thus existing Tariffs to address grid abnormal conditions should not be negatively impacted but enhanced if necessary.
- The capability to efficiently allow lower levels of import or export to address an abnormal condition can only be implemented when SCE has developed, tested, and implemented all the systems (such ADMS) needed to support DERMS communication, and orchestration of DERS in the grid under normal and abnormal conditions.

- All DERs participating in this type of interconnection must be connected to SCE DERMs and must provide real-time (typically 3-5 second interval) or near real-time (typically 15-minute interval) communication as may be determined by SCE.
- Red line accepted or discussed for alignment.

4.2.4.2 PG&E Consensus, Non-Consensus, and/or Qualifications for Business Case B

PG&E supports the concept of a coordinated DER operational response to near real-time or pre-planned abnormal grid conditions with the following qualifications:

- This business case should not negatively impact the DSO from performing duties to manage abnormal grid conditions safely and efficiently under existing rules and Tariffs.
- The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections.
- All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E.
- All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO.
- The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios.
- The DSO does not offer a guarantee for the availability of any non-firm capacity.
- Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations.
- Not all distribution constraints may be able to be mitigated via a flexible interconnection.
- For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

4.2.4.3 SDG&E Consensus, Non-Consensus, and/or Qualifications for Business Case B

SDG&E agrees that implementing the latest capabilities for enhancing information exchange and interoperability between DSOs and DER operators is highly important. It is essential that DSOs be able to address emerging and planned maintenance events through orderly processes, including communications with DER operators. However, in emergency events that require immediate system reconfiguration to avoid equipment and property damage or safety risks, DSOs must be able to disconnect DERs immediately, with after-the-fact notification to DER operators as to triggering event and expected recovery process. As DERMS capabilities are developed, they will need the ability to handle these severe events, and the actions taken in less severe cases. Evolution of suitable communication infrastructure and standards is a prerequisite.

4.2.4.4 CAISO Consensus, Non-Consensus, and/or Qualifications for Business Case B

The ISO Supports Business Case B so long as the IOU/DSO Non-Consensus and/or Qualifications are remedied.

4.2.4.5 Enphase Consensus, Non-Consensus, and/or Qualifications for Business Case B

In general, it looks very good, and Enphase supports the Business Cases.

4.2.4.6 IREC Consensus, Non-Consensus, and/or Qualifications for Business Case B

IREC envisions that close to "real-time" signaling and/or controls will be necessary to fully make use of the available time-varying hosting capacity on the distribution system. This leads to the concept of "flexible interconnection." Allowing for the use case of "firm export and/or import limits" plus optionally "non-firm export and/or import capacities" would benefit DER deployment and distribution system optimization. These non-firm limits could be authorized by the DSOs (via updated schedules, signals or even commands) when they determine in the near-term that there would not be impacts on the safety and reliability of the grid.

4.3 Business Case C: Operational Flexibility for DER Services under Normal Conditions

4.3.1 Business Case C: Description

4.3.1.1 Different Types of DER Services

Business Case C addresses the operational flexibility requirements and capabilities for providing DER services to support DSOs, communities, CAISO, DER owners / aggregators, and society under normal grid conditions in the High DER future. As noted in Business Case B, DSOs may require mandatory actions under abnormal conditions. In Business Case C, DER operators may voluntarily take actions in response to incentives under normal conditions, or even if there may be pending abnormal conditions but the DSOs are not (yet) mandating specific actions.

These DER services will become increasingly necessary as more electrification (in particular electric vehicles) rapidly occurs, as increasing numbers and capacities of DER systems are interconnected, and as improved DSO ADMS/DERMS capabilities are available that could be used to detect when grid conditions are strained as well as when they do not have voltage or congestion problems. The focus of Business Case C, then, is to optimize the use of firm and non-firm capacity to support these various DER services.

There is not a clear demarcation between DER services that are focused only on providing safety and reliability support to the DSO's distribution system versus those that may support other stakeholders (e.g., CAISO, communities, DER owners, and society), but some terminology may be useful to distinguish between the goals of these DER services:

- **DSO services** provide safety and reliability support to the distribution grid, such as by limiting exports or imports to minimize overloads and by providing voltage support.
- **Community services** are focused on providing services to customers within a community, such as using Virtual Power Plants (VPPs) and non-islanded microgrids for financial purposes, and islanded community microgrids for reliability purposes (relevant parts of Business Case F are included in this Business Case C).
- **Ratepayer services** support the use of DER systems to minimize the necessary distribution system upgrades provided by DSOs.
- **CAISO services** are focused on providing services to CAISO (see Business Case G).
- **DER aggregator or owner services** are focused on providing benefits to DER aggregators or owners such as supporting their business requirements, permitting energy arbitrage actions for financial benefits, and utilizing their DER versus alternate resources to provide grid support.
- **Societal services** are focused on DER capabilities for supporting California and ratepayers on progressing toward California's 2045 goals for carbon neutrality.

4.3.1.2 DSO Services

DSO services provided by DER systems could support DSOs by helping them to meet their safety, reliability, efficiency, and resource adequacy (RA) requirements. In particular, when DSOs have more capabilities and information on the distribution grid, they will be able to manage grid conditions more effectively. For instance, based on more accurate information and on power flow study capabilities, they will be able to assess where more or less power might be needed on circuits and authorize the use of non-firm export and/or import capacity or to incentivize the minimum export or import of power. Although contractual arrangements and incentives are not addressed in this report, it is expected that some form of incentives will be involved.

If the DSO needs both exports and imports during a day to provide resource adequacy on certain circuits, the DSO could require some DER facilities, VPPs, or community microgrids to establish minimum export and import requirements. As shown in Figure 16, actual exports and imports could be constrained between the authorized export and import limits while still meeting the minimum export and import requirements.

Figure 16: Example of Actual Exports and Imports Constrained between Authorized Operational Limits and Minimum Export and Import Requirements

4.3.1.3 Community Microgrid Services

Although most distribution services may focus on DSO support, some distribution services could also provide community support, such as planning to ensure adequate community microgrid generation (local resource adequacy) in case of grid outages and providing lower cost energy to communities during peak periods through community management of DERs (see Business Case F). Community services could include planning and managing the microgrid:

- When not islanded, the community microgrid could:
  - **DSO service:** Act similarly to a Virtual Power Plant (VPP) and provide DSO services for safety and reliability.
  - **Community service**: Provide services to its community customers by managing the community DER systems to optimize energy costs, efficiency, and reliability.
  - **Society service**: Provide services to society by optimizing the use of renewable energy.
- When islanded, the community microgrid could:
  - **DSO service**: Black start as a microgrid.
  - **Community service**: Manage the community DER systems in a sustainable manner for as long as possible

4.3.1.4 Ratepayer Services

Increased demand for electricity is occurring due to the increased electrification of transportation (EVs) and automation systems (heat pumps, consumer electronics, etc.). Climate change is also impacting the operation of the distribution grid even during normal operations. Heat waves, fires, and unusual storm events are occurring more often, causing the distribution grid to operate under tighter conditions with less operational margins. In the past, these conditions would have required the DSOs to build new capacity and include more contingency measures to meet the "obligation to serve". However, upgrading the distribution system is very expensive, could increase ratepayers' Tariffs, and might not be achievable in a timely manner. Alternatively, DER systems may be able to provide many types of distribution services to alleviate these conditions and at least to defer if not avoid the need for grid upgrades[24]. These distribution services would primarily focus on the DER facilities services related to managing their active power exports and imports, while also providing voltage support services.

4.3.1.5 DER Owner or Aggregator Services

DER owners and/or the aggregators who manage groups of DER systems could also optimize their exports and imports for their own business purposes, particularly if the DSO is able to assess actual capacity situations and can authorize non-firm capacity on a granular basis. An example of more granular firm limits and authorized non-firm capacity for supporting DER services is shown in Figure 17, where firm limits are shown and blue and additional non-firm limits that vary through the day are shown in orange. In this figure a Power Purchasing Agreement (PPA) of a large power plant incentivizes it to export more during the early morning and late afternoons and evenings to counteract the "duck curve"[25] effect as available solar energy rapidly decreases while loads rapidly increase (large power plants use their solar to charge batteries during the day so they are allowed to export storage power in the evenings).

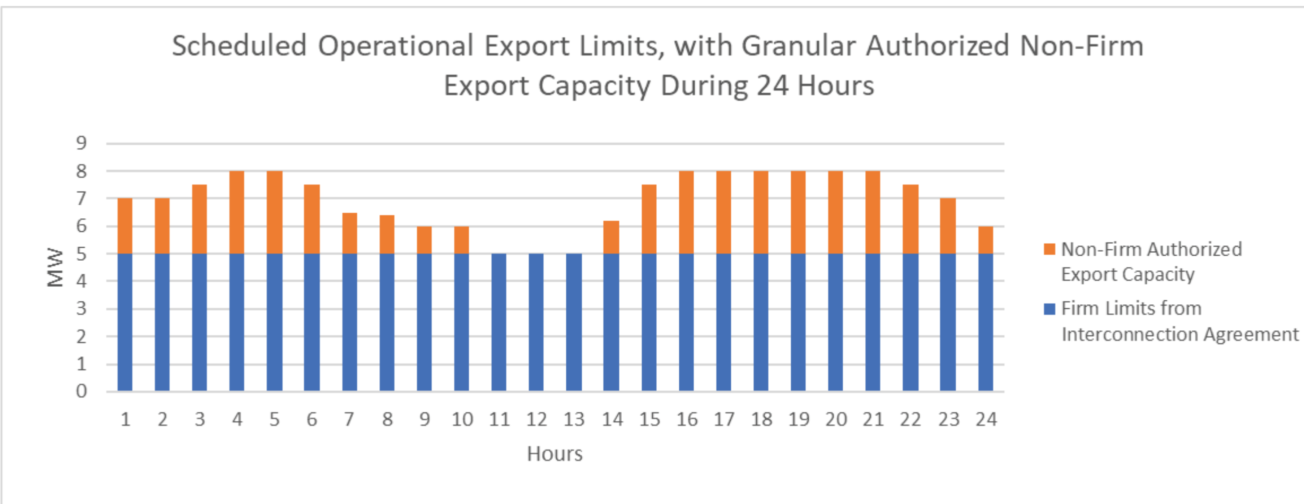

Figure 17: Scheduled Operational Limits over 24 Hours

Actual exports would be constrained by these limits but would not necessarily utilize them, as illustrated in Figure 18 where the red line of actual export often does not reach the export limits shown as bars.

[24] *These DER services may or may not involve incentives, but the issue of compensation is out-of-scope for the SIOWG. The SIOWG is addressing only the technical issues associated with distribution services that could be provided by DER.*

[25] *https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf*

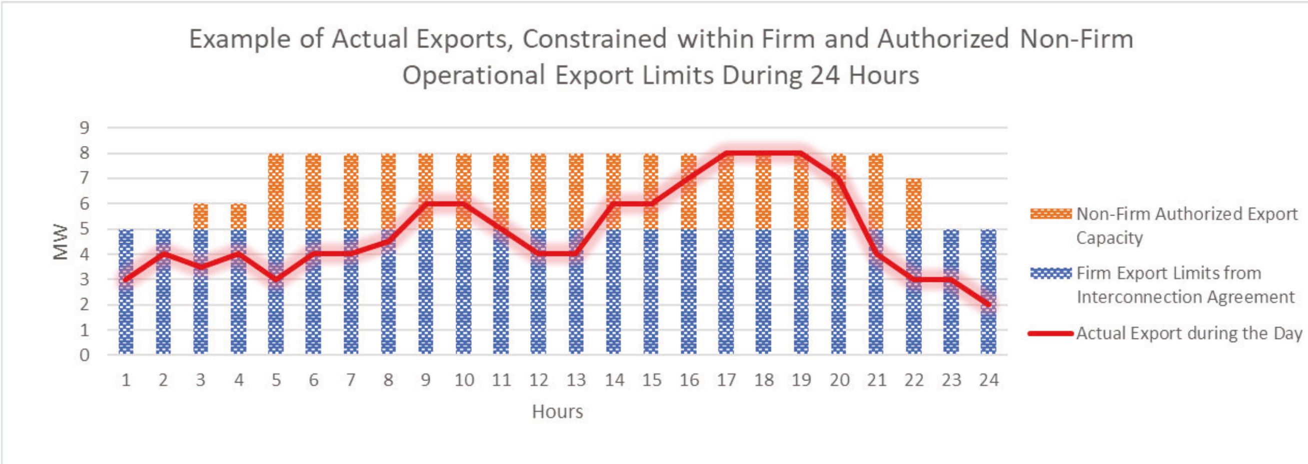

Figure 18: Actual Exports Constrained within Firm and Authorized Non-Firm Export Limits

4.3.1.6 CAISO Services

Some services could support CAISO for resource adequacy and operational reserves, so long as these services do not negatively impact the distribution grid safety or reliability. CAISO has identified three high-priority services: Fast Frequency Response (FFR), Synthetic or Artificial Inertia Frequency-Active Power, and Power Factor Limiting (Correcting).

The DER system flexibility in exports and imports could also provide DER owner and aggregator services to help manage congestion on specific circuits during heat waves or other situations. CAISO Location Marginal Pricing (LMP) maps provide prices for both energy and congestion, reflecting those needs as shown in Figure 19. LMP estimates the cost of delivering electricity to a particular location at a particular time based on three components: generation, congestion of the electrical grid, and losses. When permitted by the DSO, DER systems could be incentivized to export more or less power (or import less or more power) on location-specific congested circuits in a manner similar to the transmission-level use of LMP congestion pricing. These LMP congestion pricing values could be a proxy for location-specific congestion support needs that might be fulfilled by DER systems. Aggregators could coordinate multiple DER facilities and/or VPPs to support these CAISO-level services, particularly if the DSOs have permitted the non-firm export (and/or import) capacity for those DER facilities.

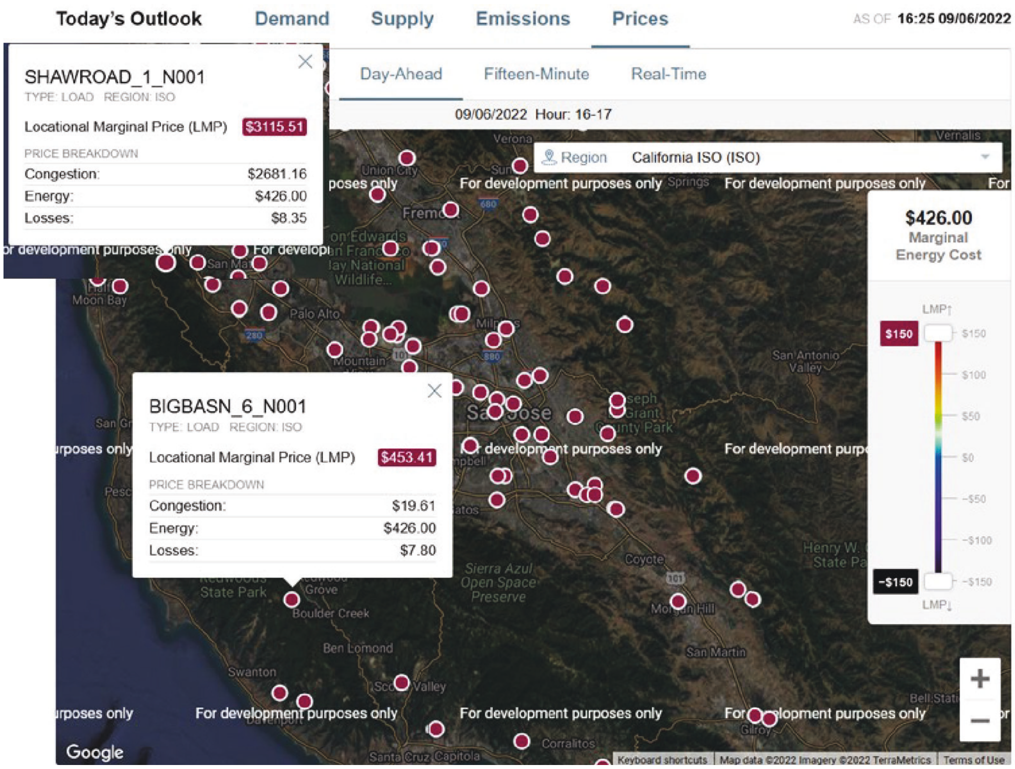

Figure 19: CAISO LMP pricing of energy and congestion during 9/6/2022 heat wave

During high wind and low load conditions, the DSO could authorize more **Non-Firm import capacity**, as indicated by a negative price for congestion in Figure 20. This would permit more effective utilization of the wind power.

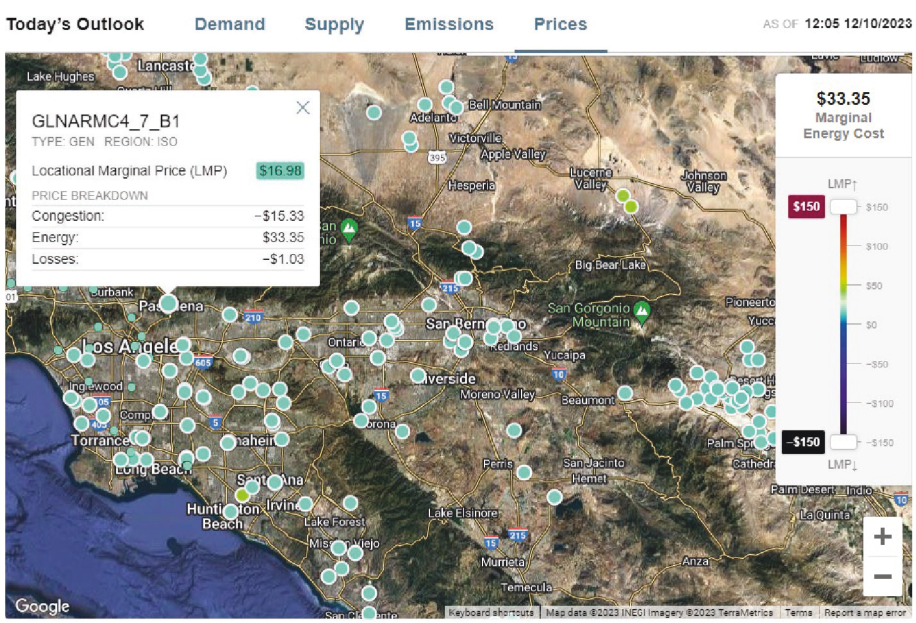

Figure 20: CAISO LMP pricing and congestion during high wind and low load conditions

4.3.1.7 Societal Services

As capacity on circuits becomes more accurately measured and actively managed by the DSOs, more renewable energy DERs could be interconnected to the grid, thus supporting California's goals of carbon neutrality by 2045.

In particular if one DER facility has unused capacity (export or import), that unused capacity could be allocated to a different DER facility through the management of the permissions to use non-firm capacity.

4.3.2 Business Case C: Purpose to Solve Problems or Provide Opportunities for Different Stakeholders

While Business Case A covers what capabilities and flexibility could be added to Interconnection Agreements or Limited Load Profiles through the inclusion of non-firm limits, and Business Case B considers DER operations that are mandated by DSOs to solve problems in abnormal situations, the purpose of Business Case C is to envision how flexibility could be leveraged under normal using DER systems to support grid operations through incentives. These DER services can be provided for the for the benefit of the grid's reliability and safety. This will create benefits for the ratepayers through potential avoidance or deferral of grid upgrades, to the financial benefit of DER owners, and for the ultimate benefit of society and California as more renewable energy will be utilized.

It is expected that the increased use of DER capabilities for grid services will necessitate significant changes to both distribution planning and operations. Specifically, potential opportunities for DER to provide grid services would need to be considered early in the capacity assessment process, to weigh them against the costs and benefits of grid upgrades. The expectation of how to ensure DER compliance when providing a grid service would need to be built into the planning and operations processes. Then the process for grid operators could leverage these DER services in normal grid conditions would need to be incorporated into grid operations.

The primary distribution services identified by the SIOWG include the ability to limit the export of DER generation and/or import of power for charging storage, electric vehicles, and other loads at specific sites to avoid thermal overloads or voltage problems in the distribution system. Specifically, DER facilities and VPPs could provide the following distribution services to the DSOs:

- Limiting export power if and when excess power could cause congestion or thermal overloads on the circuit, even if the overloads are not at the DER site.
- Limiting export power if and when excess power could cause voltage levels to exceed their limits on the circuit, even if the voltage problems are not at the DER site.
- Limiting import power if and when excess loads could cause congestion or thermal overloads on the circuit, even if the overloads are not at the DER site.
- Limiting import power if and when excess loads could cause voltage levels to exceed their limits on the circuit, even if the voltage problems are not at the DER site.
- Require or incentivize additional minimal or exact export of power if loads along the circuit could cause thermal overloads or voltage problems. As an example, this situation could occur for electric vehicle charging stations if their circuit does not have adequate generation capabilities to cover the load demand caused by fast charging during a storm or heat wave, or occasionally during specific times of the day, week, or year. Although the charging station might be asked to limit its demand, an alternative could be to have a neighboring DER facility export additional generation as a distribution service.
- Require or incentivize additional import of power if generation export at other sites could cause thermal overloads or voltage problems. Although not seen as a common situation, it could be that the generation export at the other sites is required for other services, including for transmission ancillary services.
- Responding to voltage fluctuations or inefficient high voltage levels by changing active power export and/or import. Although voltage management was not identified as high priority, DER systems could still provide this support as a distribution grid service.

- Responding to CAISO requirements for additional power export, minimizing power import, vice versa, and/or providing reactive power support, while still ensuring those responses to not adversely affect the distribution system per the DER facility's firm limits and its authorized non-firm additional export and/or import capacity.
- Responding to heat waves and/or storms by providing export power from stationary storage systems and electric vehicles which are not normally permitted to export if they were charged with non-renewable energy but would be included if within the firm and/or authorized non-firm power export.

Although this discussion of distribution services is focused on supporting the distribution grid for the safety and reliability purposes of DSOs and their ratepayers, the DSOs ***ought or should*** use their analyses to permit DER facilities to support the DER owner purposes (e.g., energy arbitrage) by utilizing their non-firm export and/or import capacities as "operational firm limits" if that use is determined not to be detrimental to grid reliability or safety. Those DERMS analyses could develop more granular time-of-day, day-of-week, and week-ahead schedules of "operational firm limits" for the DER facilities. This would not only benefit the DER owners but could also benefit society and California through the increased use of DER renewable energy to combat climate change and help meet California's renewable energy goals.

The current capabilities of the DSOs and the DER sites do not yet include methods for requiring, requesting, or providing such distribution services except for some special cases with the larger, utility-scale DER systems often directly managed by the DSOS. However, in the High DER future, many DER facilities and Virtual Power Plants (VPPs) (aggregations of DER) may be able to provide these distribution services. Therefore, planning for these future distribution services necessitates the identification of probable grid services, the procedures for establishing the methodologies for requesting the services, the means for ensuring compliance with the services, and the after-the-fact review of how well the services met the distribution grid needs. *(Any financial impacts or potential compensation for these services are out-of-scope of the SIOWG.)*

These distribution services by DER would benefit from the flexibility in the Interconnection Agreements and/or Limited Load Profiles where the firm export and/or import limits also have associated non-firm capacities that the DSOs may authorize to be used as "operational firm limits" during specified time periods, for providing grid services to the DSO and others.

The capabilities to modify export and import limits was rated as High Priority by all SIOWG members who specifically indicated their priority ratings. Near-real-time communications (< 5 minutes interactions) for situational awareness was also considered High Priority. However, it was recognized that this ability to modify or command changes to limits would require time for the deployment of DSO ADMS/DERMS and appropriate communication capabilities.

The methods for the DSOs to provide the information to the appropriate DER facilities could include:

- Updates for specific DER sites could be sent directly via communication protocols, through aggregators, or by using manual methods (phone call, text message, email, etc.).
- The schedules established for DER sites of export and/or import non-firm limits could be updated as necessary.
- Control commands could be issued to specific DER sites to modify their non-firm export and/or import capacity.

4.3.3 Business Case C: Justifications and Benefits for Stakeholders

Business Case C benefits DSOs, DER owners, ratepayers, and society by limiting the risk of thermal overloads while utilizing all the capabilities of the already interconnected DERs to increase grid efficiency and to make more effective use of available grid capacity for renewable resources.

Table 5 identifies justifications and benefits for stakeholders for Business Case C.

Table 5: Justifications and Benefits for Stakeholders for Business Case C

Business Case C Justifications and Benefits	Description of Specific Justifications and Benefits
DSO benefit: Operational safety to minimize personnel harm and equipment damage	Even in normal conditions, some events may trigger situations where taking contingency actions can minimize safety threats and possible equipment damage. These contingency actions could include the use of DER systems to minimize the threat of grid overloads and equipment damage using firm and authorized non-firm capacity to counteract those possible overloads.
DSO benefit: Operational reliability to minimize power outages	If the ADMS/DERMS identify possible contingency situations, requesting grid services from DER could help improve grid reliability and avoid grid outages with operational flexibility provided by firm and authorized non-firm capacity.
DSO benefit: Operational efficiency through active power management	If the ADMS/DERMS identify grid conditions where efficiency could be improved, DER systems could provide voltage support to improve the efficiency of the grid, especially via the volt-watt function.
DSO and Ratepayer benefit: Operational capacity to meet renewable energy goals and DSO savings from deferring construction costs	Planning for and expecting to use DER systems for grid services could permit DSOs to minimize or defer grid upgrades, thus benefiting ratepayers.
DER owner benefit: Financial benefits	DER owners would benefit financially from using non-firm capacity for distribution services, particularly if granular schedules were provided by the DSOs that allowed the DER owners to plan when they might be able to use the operational flexibility provided by firm and authorized non-firm capacity.
DER owner benefit: Ancillary services market for offering grid services to the Transmission System Operator (TSO) and/or DSO	Some DER owners might be able to offer ISO ancillary services, such as Reg Up and Reg Down, if they are able to use operational flexibility provided by their firm and authorized non-firm capacity for that CAISO service.
Ratepayer benefit: Provision of grid services even to ratepayers who do not own these DER implementations	Ratepayers will benefit from the DSOs avoiding or deferring grid upgrades if DER systems can provide compensating support when needed.
Societal benefit: Reduce use of fossil fuels	Using more of the non-firm capacity for more DER reduces the use of fossil fuels and helps California meet the goals of SB100.

4.3.4 Business Case C: SIOWG Participant Consensus, Non-Consensus, and/or Qualifications

4.3.4.1 SCE Consensus, Non-Consensus, and/or Qualifications for Business Case C

SCE supports this concept with the following qualifications:

- SCE does not agree that most of the use cases identified in this section are in fact “Distribution Grid Service”. (Note: DER distribution services were separated into DSO services and other types of services to clarify this issue.)

- Strike section that SCE views as not being "Distribution Service" (namely, benefits to DER owners and society)
- All non-distribution grid services should be removed from this section.
- Distribution grid Services are those services that provide support to the operations of the distribution grid under normal and/or abnormal grid condition likely ties to monetary or equivalent compensation.
- The capability to provide Distribution services can only be implemented when SCE has developed, tested, and implemented all the systems (such ADMS) needed to support DERMS communication, and orchestration of the DERs which provide distribution service. This functionality may be provided by other means as determined by SCE.
- All DERs participating in the Distribution Service operation must be connected to SCE DERMs and must provide real-time (typically 3-5 second interval) or near real-time (typically 15-minute interval) communication as may be determined by SCE. This functionality may be provided by other means as determined by SCE.
- Red line accepted or discussed for alignment.

4.3.4.2 PG&E Consensus, Non-Consensus, and/or Qualifications for Business Case C

PG&E supports the concept of DER systems and VPPs providing distribution grid services with the following qualifications:

- There should be more clarity in what constitutes a grid service. The "do no harm" DER responses under a flexible interconnection for normal and abnormal conditions are not grid services. Suggest potentially removing grid services from Business Cases A and B and focus Business Case C on grid services for both normal and abnormal situations.
- The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for grid services.
- All DERs participating in grid services must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E.
- All DERs participating in grid services must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO.
- Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations.
- The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios.
- Not all distribution constraints may be able to be mitigated efficiently via distribution services.
- Not all customers are suitable for providing distribution services.
- For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

4.3.4.3 SDG&E Consensus, Non-Consensus, and/or Qualifications for Business Case C

SDG&E agrees with SCE that the meaning of "distribution system services" should be clarified before finalizing this section. SDG&E will also need to coordinate and reconcile its ADMS/DERMS development with the resulting vision for these services.

SDG&E does not believe it is necessarily the case that "all DERs" providing distribution services must be connected to SDG&E's ADMS/DERMS. There may be arrangements where SDG&E communicates with an aggregator who takes on the contractual responsibility for ensuring the DERs within its aggregation operate in accordance with the instructions that SDG&E's ADMS/DERMS provides to the aggregator.

SDG&E notes that the functionalities desired for specific services may vary as to their placement within specific subsystems, such as ADMS, DERMS, and inverters. The path chosen will depend on the nature of the service, the parties involved, and the choices for equipment and software. At this juncture, there is no universal consensus as to what functions should be included in each of the major subsystems. The rule making will need to keep abreast of the changes occurring in these technologies and the related standards.

4.3.4.4 CAISO Consensus, Non-Consensus, and/or Qualifications for Business Case C

The ISO Supports Business Case C so long as the IOU/DSO Non-Consensus and/or Qualifications are remedied.

4.3.4.5 Enphase Consensus, Non-Consensus, and/or Qualifications for Business Case C

In general, it looks very good, and Enphase supports the Business Cases.

4.3.4.6 IREC Consensus, Non-Consensus, and/or Qualifications for Business Case C

IREC envisions that close to "real-time" signaling and/or controls will be necessary to fully make use of the available time-varying hosting capacity on the distribution system. This leads to the concept of "flexible interconnection." Allowing for the use case of "firm export and/or import limits" plus optionally "non-firm export and/or import capacities" would benefit DER deployment and distribution system optimization. These non-firm limits could be authorized by the DSOs (via updated schedules, signals or even commands) when they determine in the near-term that there would not be impacts on the safety and reliability of the grid.

5 Use Cases 1-3: Operational Flexibility in Export Use Cases Supporting Business Cases A, B, and C

5.1 Export Use Cases 1-3 Supporting Business Cases A, B, and C

Each of the Business Cases A, B, and C ("*what" is required*) identified the same set of 3 Use Cases ("*how" to meet the what requirements*) related to export limits as applicable to their objectives and purposes, and each of these Use Cases were rated as high priority for potentially being able to support those Business Case requirements. Specifically, Business Case A addresses the contractual flexibility that could be provided by having both firm limits and non-firm capacity contractually stated, while Business Case B identifies the requirements for scheduling and commanding limits for assisting during abnormal conditions and Business Case C identifies those requirements for Distribution Services during normal operations.

The **firm export limits** would reflect the DER operator's agreement to DSO export limit requirements, based on the DER facility's generation, storage, and load capabilities, the DSO's assessment of current capacity constraints on the affected circuits, and any decisions on upgrading the grid to minimize those capacity constraints.

The **non-firm export capacity** would reflect the DER operator's expectations of being able to export additional power and the DSO's assessment that such additional export might be feasible in the future or during certain time periods. The utilization of such non-firm export capacity during operations would be termed "operational export limit" for the time period authorized by the DSO.

This approach of using firm limits and non-firm capacity is new. DSOs will require additional studies, assessments, and near-real-time information to determine how much and when to authorize non-firm export capacity. Many of the tools for such evaluations are (probably) in the designs for their ADMS/DERMS capabilities, but more tools and more detailed and timely information on the grid conditions may also be needed. In addition, regulatory procedures will need to be adjusted or improved to address the many issues that could arise from this new approach. Some of those regulatory issues are identified in this report, but it is expected that many additional issues will become evident over time. For instance, how should any unused capacity that was allocated to one DER owner/operator be potentially made available to other DER owner/operators (see discussion in Annex B).

The Use Cases identified three different ways to support the Business Cases. These are shown in Table 6.

Table 6: Matrix of Business Cases to Export Use Cases

Use Cases / Business Cases	Use Case 1. Scheduled Maximum Export Limit	Use Case 2. Commanded Maximum Export Limit	Use Case 3. Generation Minimum Export Requirement
Business Case A: Flexibility of Export and/or Import Limits in DER Interconnection Agreements	**Use Case A1:** Inclusion of Firm Limits and Non-Firm export capacity for scheduling maximum export limits in Interconnection Agreements	**Use Case A2:** Inclusion of Firm Limits and Non-Firm export capacity for commanding maximum export limits in Interconnection Agreements	**Use Case A3**. Generation Export Minimum Requirement in Interconnection Agreements
Business Case B: Abnormal Grid Conditions with Pre-planning or Near Real Time Responses	**Use Case B1:** Scheduled Firm Export Limits and Non-Firm Export Capacity Before or During Abnormal Conditions	**Use Case B2:** Commanded Firm Export Limits and Non-Firm Export Capacity for Abnormal Conditions	**Use Case B3:** Minimum Generation Export Requirement for Abnormal Conditions
Business Case C: DER Systems and VPPs Providing Distribution Services under Normal Future Grid Conditions	**Use Case C1:** Scheduled Firm Export Limits and Non-Firm Export Capacity for Distribution Services	**Use Case C2:** Commanded Firm Export Limits and Non-Firm Export Capacity for Distribution Services	**Use Case C3**: Minimum Generation Export Requirement for Distribution Services

Although each of the Use Cases provided different aspects to help meet the different goals of the 3 Business Cases, it is important to see them together since they are closely linked in their technical requirements.

Note: Use Case 4, Maximum Import (Load) Limit, also supports Business Cases A, B, and C, but is covered in Section 6 since the implications of limiting loads has significantly different regulatory issues.

5.2 Use Case 1: Scheduling of Firm Export Limits and Non-Firm Export Capacity

5.2.1 Use Case A1: Inclusion of Firm Export Limits and Non-Firm Export Capacity for Scheduling Maximum Export Limits in Interconnection Agreements

Use Case A1 addresses the High DER Future where flexibility provided by scheduled firm export limits and additional non-firm export capacity could be included in Interconnection Agreements.

This scheduled flexibility includes:

- **Firm schedule**. The Interconnection Agreement would include a “firm schedule” based on firm export limits. This “firm schedule” might be implicit as a single setting (based on the maximum export capabilities of the DER facility) or might be explicit with variations for different time periods.
- **Update scheduled capacity**. The Interconnection Agreement includes the ability for the DSO and the DER owner/operator to agree on updates to the export limits using any non-firm DER export capabilities.
- **Increased granularity**. The Interconnection Agreement includes the ability to set scheduled limits **by time of day, by day of week, by month, and by season** for non-firm export capacity. This increased granularity would be based on the DSO ADMS/DERMS capabilities to provide more granular assessments of circuit capacity.
- **Timely schedule updates.** The Interconnection Agreement includes the ability to set scheduled export limits **day-ahead** and/or **hour-ahead** for non-firm export capacity. This increased timeliness would be based on the DSO ADMS/DERMS capabilities to provide more timely assessments of circuit capacity and would be most pertinent for actual or planned/forecast abnormal conditions, for DSO-related distribution services, but also for DER operator benefits.

The rules for how much non-firm export flexibility would be allowed and when such flexibility might be undertaken, would require detailed discussions and eventual agreements in a CPUC OIR in the High DER future.

5.2.2 Use Case B1: Scheduled Firm Export Limits and Non-Firm Export Capacity Before or During Abnormal Conditions

Since DSOs are permitted to modify firm export limits for abnormal conditions, Use Case B1 addresses the use of scheduling of both firm export limits and non-firm DER export capacities in the High DER Future during abnormal conditions.

- An **abnormal** grid condition may be planned or unplanned. In either case, both firm and non-firm export limits can be scheduled since the DSOs always may modify export limits for abnormal conditions.
- For **planned** or **forecast abnormal conditions** (such as due to maintenance):
  - The DSO would provide the DER Operator with a modified “abnormal conditions” schedule of firm export limits, as well as non-firm export capacity limits if applicable, for the expected duration of the planned or forecast abnormal condition.
  - If planned work exceeds the expected time, the DSO would update the “abnormal conditions” schedule and/or otherwise inform the DER Operator of additional time required to be on schedule.
  - The DSO would confirm with DER operator when grid has returned to normal conditions, at which time DER System can revert to the normal Interconnection Agreement limits for the firm export limits and/or any “normal conditions” schedule of non-firm export limits authorized by the DSO.
- For **unplanned abnormal conditions** (such as grid fault), the DSO obviously would take immediate steps to mitigate or prevent any further impacts due to the unplanned abnormal condition which could include requiring zero export. However, when the situation has been assessed, the DSO would provide the DER facility with a modified “abnormal conditions” schedule of firm export limits, as well as non-firm export capacity if applicable, for the expected duration of the abnormal condition.
  - Consideration should be taken with respect to the length of time the abnormal condition might be in place. For short periods of abnormal condition, it may be more practical to request the DER facility to export zero or some minimal power in lieu of preparing, delivering, and modifying the operation of the DER facility with an “abnormal schedule”. For longer periods of abnormal conditions, the DSO would provide the “abnormal conditions” schedule and/or otherwise inform

the DER facility of the time required to be on “abnormal conditions” schedule. If communication capabilities are available, the modified scheduled limits could be sent electronically.

– The DSO would confirm with DER operator when grid has returned to normal conditions, at which time DER System can revert to the normal Interconnection Agreement limits for the firm export limits and/or any “normal conditions” schedule of non-firm export capacity authorized by the DSO.

– The DSO could also utilize scheduled restoration of both firm export limits and non-firm export capacity to assist during distribution system restoration (see Figure 21).

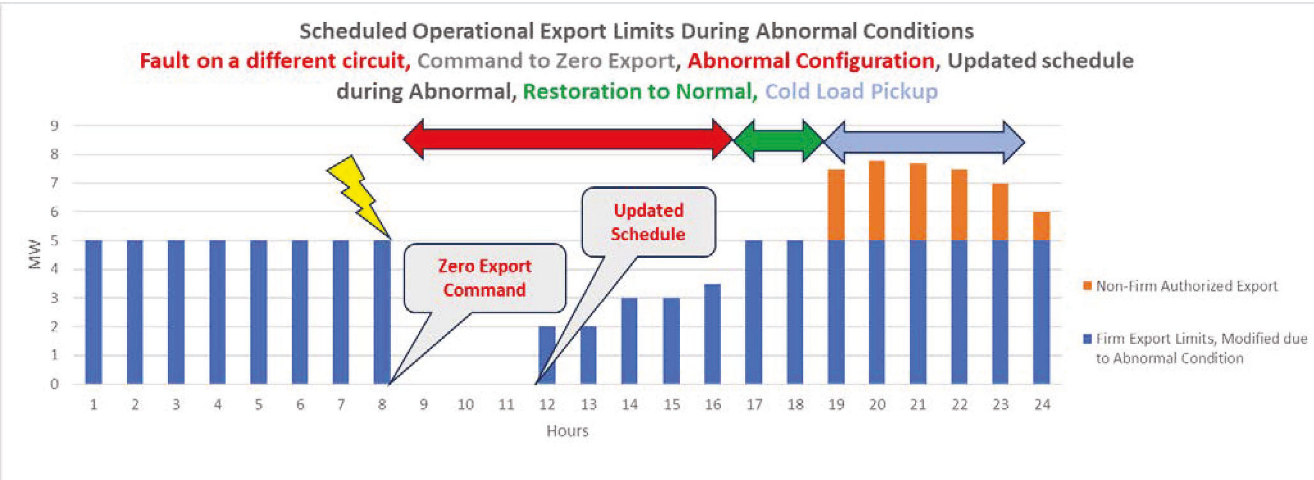

Figure 21: Updated schedules during distribution system restoration

5.2.3 Use Case C1: Scheduled Firm Export Limits and Non-Firm Export Capacity for Distribution Services

Use Case C1 addresses use of scheduled **firm export limits** and **non-firm additional authorized export capacity** for distribution services (see Business Case C) including assessed and authorized services for transmission and CAISO. For most distribution services, only the non-firm export capacity would be scheduled as “operational export limits”, but modifications to firm export limits might be scheduled in certain situations such as heat waves (compensation for modifying firm export limits is out-of-scope for the SIOWG but would be expected).

The types of schedules for distribution services would depend on their purpose (thermal overload concerns, voltage problems, improve efficiency, lower the risk of contingencies, support use of excess capacity, etc.) as well as the abilities of the ADMS/DERMS and communications capabilities to develop the requirements of the desired distribution service.

Specific scheduled distribution services for grid support include:

- During heat waves or other times of grid stress:
  – DER systems could schedule the export of additional power, including authorizing additional non-firm capacity.
  – The schedule of import limits could minimize any non-firm power.
  – For some DER systems, the schedule would include minimum export requirements.
- If storms might cause PSPS events, different non-firm export capacities could be scheduled to help ensure microgrids could have enough power if they need to be islanded.
- If thermal overloads are a potential issue, the DSO could update the schedules of authorized non-firm capacity of all affected DER systems.

- If voltage levels could become an issue, the DSO could schedule voltage support functions such as volt-var and/or volt/watt, including any adjustments to the authorized non-firm capacity to avoid impacting the firm export limits.

5.2.4 Use Case 1 Priority Ratings

Each of these Use Cases were identified as high priority although the details of when they might be available were rated differently by different groups, depending on the purpose. Table 7 shows the Use Case 1 variations were rated High Priority with different caveats on the possible time they might be implementable. The term "near-term" implies about 3-5 years for the development of the technologies but would depend on the timeframes of the regulatory and testing processes necessary for final deployment.

Table 7: Use Case 1 Priorities for Scheduled Maximum Export Limit

Use Case 1 Variations	PG&E	SCE	SDG&E	350BA	CALSSA
Update the schedule of authorized non-firm export capacity		High Priority (Technology should/could become available in near-term	High Priority: Technology already available or in near-term	High Priority: Technology already available or in near-term	Customers wanting to increase capacity above what is in their IA should submit an interconnection application and take their place in the queue
Increased granularity of the scheduled maximum export limits by time of day and by day of week.	High Priority: Technology should/could become available in near-term	High Priority: Technology should/could become available in near-term	High Priority: Technology already available or in near-term	High Priority: Technology should/could become available or in near-term	
Timely updates of the scheduled maximum export limits for day-ahead and/or hour-ahead timeframes.	High Priority: Technology should/could become available in near-term	High Priority: even though technology only available in long-term (> 5 to 10 years)	High Priority: Technology already available or in near-term	High Priority: Technology should/could become available or in near-term	

5.2.5 Use Case 1: Regulatory Issues for Scheduling Firm Export Limits and Non-Firm Export Capacity

The regulatory roadmap for Use Case 1, Scheduling Firm Export Limits and Non-Firm Export Capacity, may involve exploring the possible methodologies in the next Rule 21 Tariff OIR or other appropriate proceedings. Essentially, looking into the High DER Future, the question is what the DSOs should be requested/mandated to provide to DER operators in the Interconnection Agreements (Business Case A) to permit them to better plan for abnormal conditions (Business Case B) and to provide distribution services for improved reliability, efficiency, and better utilization of capacity for renewable resources (Business Case C).

The regulatory and technical issues for scheduling firm export limits and non-firm export capacity in the High DER Future include:

- How could/should scheduling of firm export limits and non-firm export capacities be incorporated into Interconnection Agreements from a regulatory perspective?
- How would the firm export limits and the non-firm export capacities be determined for Interconnection Agreements? Which studies would be involved and what screens would be affected?
- How could the schedules of firm export limits and non-firm export capacity be utilized to meet abnormal conditions? Which DSO studies, power flow assessments, and planning would be involved? What communication requirements (if any beyond phone calls) would be necessary? What should DER operators be expected to implement and test?
- How could the firm export limits and non-firm export capacity be included in the DSO Interconnection Agreements to support distribution services? Which DSO studies, power flow assessments, and planning would be necessary to authorize the export of non-firm capacity? What communications and coordination requirements would be necessary between the DSO and the DER operator? What should DER operators be expected to implement and test?
- What additional data should be collected to determine what timing and values should be provided in schedules, particularly during abnormal conditions?
- What validation during and after-the-fact could be required between the DSO and DER facilities to ensure compliance in near-real-time? Are AMI systems able to support such validation? Could communications with aggregators associated with the DER facilities be utilized?
- What additional power system monitoring by the DSO for DER facilities > 1 MW and for selected smaller DER facilities, might be needed to help plan and validate the assessments by DSOs to create the schedules for other DER facilities.
- Although out-of-scope for the SIOWG, it will be critical to determine what regulations would be necessary to address DSO compensation obligations for short-term and long-term “abnormal” conditions, including what constitutes “abnormal”, what are the definitions of short-term and long-term, and what actions DSOs should take to alleviate the “abnormal” condition. For instance, could “abnormal” also include wide-spread or transmission-related power system conditions, such as calls for more generation or less load during heat waves, or notifications of PSPS situations resulting in the formation of microgrids.

To date, regulations have not addressed the possibility of flexibility (firm and non-firm limits) in Interconnection Agreements with respect to active power export limits. It is also clear that actually taking advantage of such flexibility will require the DSOs to have ADMS/DERMS capabilities, including long-term and short-term planning tools. Therefore, it is expected that this Use Case will require significant time and resources to investigate and rule and eventually test on different aspects.

Given the regulatory complexity, it may be appropriate to break the Business Case into its constituent Use Cases and focus on each of those more or less independently from a regulatory perspective. For instance, Use Case A1, Inclusion of Firm and Non-Firm Export Limits in Interconnection Agreements, may be handled through the existing Limited Generation Profile (LGP) effort, while the Use Case B1 and C1 might require extensive assessments in different regulatory proceedings. These issues are discussed in more detail in Section 11 Considerations for CPUC Actions.

5.2.6 Use Case 1: SIOWG Participant Consensus, Non-Consensus, and/or Qualifications

5.2.6.1 SCE Consensus, Non-Consensus, and/or Qualifications for Use Case 1

SCE supports this concept with the following qualifications:

- Strike section that SCE views as not being "Distribution Service" (namely, benefits to DER owners and society)
- SCE does not agree that most of the use cases identified in this section are in fact "Distribution Grid Service".
- All non-distribution grid services should be removed from this section.
- Distribution grid Services are those services that provide support to the operations of the distribution grid under normal and/or abnormal grid condition likely ties to monetary or equivalent compensation.
- The capability to provide Distribution services can only be implemented when SCE has developed, tested, and implemented all the systems (such ADMS) needed to support DERMS communication, and orchestration of the DERs which provide distribution service. This functionality may be provided by other means as determined by SCE.
- All DERs participating in the Distribution Service operation must be connected to SCE DERMs and must provide real-time (typically 3-5 second interval) or near real-time (typically 15-minute interval) communication as may be determined by SCE. This functionality may be provided by other means as determined by SCE.
- Red line accepted or discussed for alignment.

5.2.6.2 PG&E Consensus, Non-Consensus, and/or Qualifications for Use Case 1

PG&E supports the concept of scheduling firm export limits and non-firm export capacity for DERs with the following qualifications:

- The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections.
- All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E.
- All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO.
- The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios.
- The DSO does not offer a guarantee for the availability of any non-firm capacity.
- Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations.
- Not all distribution constraints may be able to be mitigated via a flexible interconnection.
- For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

5.2.6.3 SDG&E Consensus, Non-Consensus, and/or Qualifications for Use Case 1

SDG&E supports this use case with the qualification that the definitions of terms in this report are finalized first. The DSOs should have flexibility in negotiating agreements in specific cases to set limits that are consistent with maintaining system reliability and safety in those specific cases. The limits should not become a one size fits all approach.

5.2.6.4 CAISO

The ISO Supports Use Case 1 given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads, and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSEs) along with any export capacity providing grid services to the ISO.

5.3 Use Case 2: Commanded Firm Export Limits and Non-Firm Export Capacity

5.3.1 Use Case A2: Inclusion of Firm Export Limits and Non-Firm Export Capacity for Commanding Maximum Export Limits in Interconnection Agreements

Use Case A2 addresses optionally providing **firm export limits** and **non-firm additional export capacity** in Interconnection Agreements by including DSO commands (either directly or indirectly) to modify the firm and non-firm export limits. This Use Case builds on Use Case A1 by including commands as well as schedules of export limits.

The rules for how much flexibility would be allowed and when such flexibility might be undertaken, would require detailed discussions and eventual agreements in a CPUC OIR.

5.3.2 Use Case B2: Commanded Firm Export Limits and Non-Firm Export Capacity for Abnormal Conditions

Use Case B2 addresses the ability to command changes to the firm and non-firm export limits for abnormal grid conditions that may be unplanned, planned, or forecast. These commands could be manual (phone call, email), or could be through an aggregator, or could be automated if communications are available between the DSO and the DER.

It is presumed that the commanded export limits would decrease the firm and non-firm export limits during or in anticipation of abnormal conditions. Another command would be used to revert the export limits to the previous levels after the abnormal conditions have been resolved and the grid has returned to normal. This could entail returning to a scheduled maximum export level or to unlimited export if no scheduled limit is part of the Interconnection Agreement or to using non-firm capacity to assist with cold load pickup and the load that was shifted during distribution system restoration (see Figure 22).

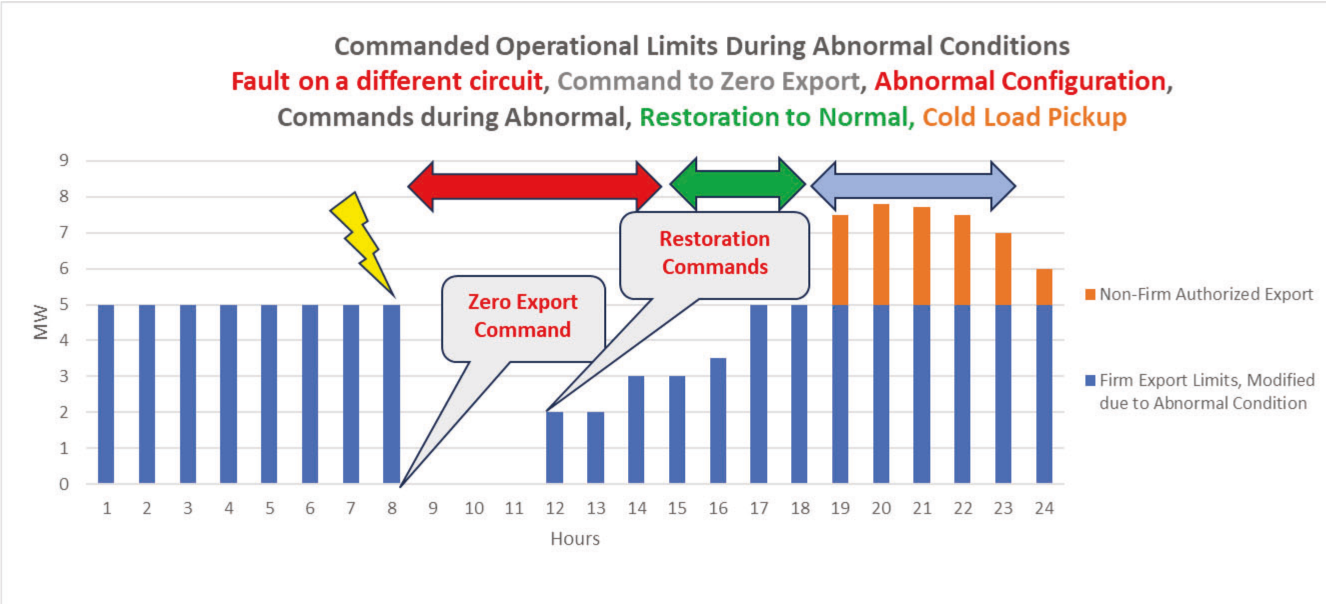

Figure 22: Commanded Firm Export Limits during Abnormal Conditions

5.3.3 Use Case C2: Commanded Firm Export Limits and Non-Firm Export Capacity for Distribution Services

Use Case C2 is similar to Use Case C1 except that the DSO could issue commands instead of schedules to set the firm and non-firm "operational export limits".

Once the DSO ADMS/DERMS and communications capabilities are able to issue commands, then the DER facilities could provide distribution services to the DSO based on Tariffs, contracts, or other incentives. These distribution services would support the goals of Business Case C.

Modifications to the firm and non-firm export limits could also be due to near-real-time assessments of capacity constraints by ADMS/DERMS applications caused by extreme weather conditions, possible fire conditions, or other external situations. The line between forecast abnormal conditions where the DSO *requires* an action, and distribution services where a DER operator *offers* to take action, could be fuzzy since both might involve compensation, but ultimately both situations would involve the DSO issuing a command to the DER operator with authorization of a non-firm export capacity value. For instance, an offer can be made at any time, but the DSO has the right to access the situation and to decide if, when, and by how much by issuing a command to trigger the action.

5.3.4 Use Case 2 Priority Ratings

Use Case C2 consists of 2 variations on commanded firm export limit and authorization for non-firm export capacity for situations during abnormal or normal grid conditions:

- **Authorized non-firm export capacity.** The DSO can issue a command to a DER that authorizes a value (watts or percent) of non-firm export capacity. This change in non-firm export capacity would reflect the results of assessment of available capacity, which may increase if the DSO determines there are fewer constraints or may decrease due to DSO's planning for contingencies.
- **Decrease firm export limit.** The DSO issues a command to decrease the firm export limit due to abnormal conditions. This command may reflect the results of contingency analyses or planned actions, thus

potentially mitigating problems caused by other customers, or during reconfiguration, planned maintenance, switching operations, and other distribution services.

As shown in Table 8, these Use Case 2 variations were rated Medium Priority or High Priority with different caveats on the possible time they might be implementable.

Table 8: Use Case 2 Priorities for Commanded Firm and Non-Firm Export Limits

Use Case 2 Variations	PG&E	SCE	SDG&E	350BA	CALSSA
Authorized Increase or Decrease of Non-Firm Capacity	Medium: Important, but not high priority at this time	High Priority: (technology may not be available for 3-5+ years)	High Priority: even though technology only available in long-term (> 5 to 10 years)	High Priority: Technology should/could become available in near-term	Better to focus on C3. Customer should have approved export capacity, then can make use of it when it is most needed. Changing the allowable export capacity is a new interconnection review.
Decrease Firm Export Limit	High Priority: Technology should/could become available in near-term	High Priority Technology should/could become available in near-term (3-5 years)	High Priority: even though technology only available in long-term (> 5 to 10 years)	High Priority: Technology should/could become available in near-term	

5.3.5 Use Case 2: Regulatory Issues for Commanded Firm Export Limits and Non-Firm Export Capacity

The regulatory roadmap for Use Case 2, Commanded Firm Export Limits and Non-Firm Export Capacity, may involve exploring the possible methodologies in the next Rule 21 Tariff OIR or other appropriate proceeding. The regulatory issues would involve:

- How could commands for firm and non-firm export limits be included in the DSO Interconnection Agreements?
- Similar to scheduled limits, what regulations would be necessary for commanded limits to address short-term and long-term "abnormal" conditions, including what constitutes "abnormal", what are the definitions of short-term and long-term, and what actions DSOs should take to alleviate the "abnormal" condition. For instance, could "abnormal" also include wide-spread or transmission-related power system conditions, such as calls for more generation or less load during heat waves, or notifications of PSPS situations resulting in the formation of microgrids.
- What additional data should be collected to determine the duration and the accumulated active power constrained by the maximum export limits, particularly during abnormal conditions.
- What communications could be required between the DSO and DER facilities to support the commands of firm and non-firm export limits? How could aggregators be used between the DSO and the DER facilities to relay the commands?

To date, regulations have not addressed the possibility of firm and non-firm export limits in Interconnection Agreements. It is also clear that actually taking advantage of such flexibility will require the DSOs to have ADMS/DERMS capabilities as well as significant expansions of power system monitoring. Therefore, it is expected that this Use Case will require significant time and resources to investigate and rule on different aspects.

5.3.6 Use Case 2: SIOWG Participant Consensus, Non-Consensus, and/or Qualifications

5.3.6.1 SCE Consensus, Non-Consensus, and/or Qualifications for Use Case 2

SCE supports this concept with the following qualifications:

- Red line changes proposed are adopted which clarify that for distribution services (normal, planned, or abnormal conditions) the DSO must have a guarantee of a minimum import. Example, if the grid has capacity needs for 2MW, then the participating DER must at minimum provide 2 MW of capacity otherwise the DSO cannot rely on the DER to meet the capacity need.
- There appears to be missing a Business case for “reducing or mitigating” interconnection costs for the benefit of the DER owner/operator. For example, allowing DSO to reduce the output of a DER (per Business Case A) eliminate the need to perform grid upgrades which would have to be paid for by the DER owner/operator.
- Red line accepted or discussed for alignment.

5.3.6.2 PG&E Consensus, Non-Consensus, and/or Qualifications for Use Case 2

PG&E supports the concept of commanded firm export limits and non-firm export capacity for DERs with the following qualifications:

- The red line changes are adopted to increase scope of commands included in this use case.
- The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections.
- All DERs participating in this type of interconnection must be connected to PG&E’s DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E.
- All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO.
- The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios.
- Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations.
- The DSO does not offer a guarantee for the availability of any non-firm capacity.
- Not all distribution constraints may be able to be mitigated via a flexible interconnection.
- For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

5.3.6.3 SDG&E Consensus, Non-Consensus, and/or Qualifications for Use Case 2

SDG&E supports this use case with the caveat that the DSO have the flexibility in negotiating agreements in specific cases to set limits that are consistent with maintaining system reliability and safety in those specific cases. The limits should not become a one size fits all approach.

5.3.6.4 CAISO Consensus, Non-Consensus, and/or Qualifications for Use Case 2

The ISO supports Use Case 2 given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads, and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSEs) along with any export capacity providing grid services to the ISO.

5.4 Use Case 3: Generation Export Minimum Requirement

5.4.1 Use Case A3. Generation Export Minimum Requirement in Interconnection Agreements

Use Case A3 addresses providing capability in the Interconnection Agreements for requiring a minimum or exact export of generation at the PCC or other Reference Point of Applicability (RPA), using either firm or non-firm generation export capabilities. In addition, with mutual agreement, the aggregators of DER facilities and Virtual Power Plants (VPPs) could respond to this requirement by including multiple DER facilities.

Use Case 3 consists of 4 variations on minimum generation export requirements that would be supported by the Interconnection Agreements:

- DSO issues a *command* to **set an exact export level** of generation at the DER system's PCC or RPA via the Set Active Power function. This command may be issued directly to DER FDERMS or may be sent to Aggregators' ADERMS.
- DSO issues a *command* for **requiring a minimum export level** of generation at the PCC or RPA via a command. This variation is the opposite of Use Case A2 in that it requires at least a minimum level of export and would need a new "smart inverter" function (Set Minimum Export Generation) that is not currently in the Rule 21 Tariff. This new function is very similar to, although the opposite of, the Set Active Power Limit smart inverter function which is in the Rule 21 Tariff. This command may be issued directly to DER FDERMS or may be sent to Aggregators' ADERMS.
- DSO issues a *schedule* of **exact export level** of generation at the DER system's PCC or RPA via the Set Active Power capability. This schedule may be issued directly to DER FDERMS or may be sent to Aggregators' ADERMS.
- DSO issues a *schedule* for **requiring a minimum export level** of generation at the PCC or RPA via the new Set Minimum Export Generation command. This variation is the opposite of Use Case A2 in that it requires at least a minimum level of export. This command may be issued directly to DER FDERMS or may be sent to Aggregators' ADERMS.

5.4.2 Use Case B3: Minimum Generation Export Requirement for Abnormal Conditions

It may be that minimum generation export requirements are not currently very important for abnormal conditions, but as more EVs are becoming significant loads on the grid, it may be that requesting minimum generation export could permit such EV charging during planned or forecast abnormal conditions.

- **Planned grid maintenance condition.** DER systems could be required to provide a minimum export to support other loads on the circuit while reconfigurations are being performed, thus avoiding having to shut down those sites or risk thermal overloads or voltage issues. Since these are planned activities, schedules could be used to establish the minimum export values, although commands could be used if circumstances or timing of the reconfiguration efforts change.

- **Forecast system emergency conditions.** In expectation of heat waves or storms, DER systems could be required to be prepared to export specific minimum amount of power, depending on last minute conditions. In this case, commands rather than schedules might be preferred.

5.4.3 Use Case C3: Minimum Generation Export Requirement for Distribution Services

Once the ADMS/DERMS and communications capabilities are able to issue commands and/or update schedules, then the DER facilities could provide distribution services to the DSO based on contracts or other incentives. If aggregators are involved, they could manage their DER facilities to achieve the desired minimum generation export. These distribution services would support the goals of Business Case C.

One of the DSO concerns is whether the DER facilities will be able to meet resource adequacy (RA) performance levels if RA is one of the distribution services. The regulations on these requirements would require detailed discussions and eventual agreements in a CPUC OIR.

Some of the distribution services for minimum generation export requirements could include:

- Require additional minimal or exact export of power if loads along the circuit could cause thermal overloads or voltage problems. As an example, this situation could occur for electric vehicle charging stations if their circuit does not have adequate generation capabilities to cover the load demand caused by fast charging during a storm or heat wave, or occasionally during specific times of the day, week, or year. Although the charging station might be asked to limit its demand, an alternative could be to have a neighboring DER facility export additional generation as a distribution service.
- Responding to CAISO requirements for additional power export, minimizing power import, vice versa, and/or providing reactive power support, while still ensuring those responses to not adversely affect the distribution system per the DER facility's firm limits and its authorized non-firm additional export and/or import capacity. In addition, the ISO would need visibility into the impact on forecasted and real-time loads, and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSEs) along with any export capacity providing grid services to the ISO.
- Responding to heat waves and/or storms by providing export power from stationary storage systems and electric vehicles which are not normally permitted to export if they were charged with non-renewable energy but would be included if within the firm and/or authorized non-firm power export.

Figure 23 illustrates and example of the minimum export requirement scheduling the operational export requirement from 1 pm hour through the 11 pm hour *{red}*, including DER operator also providing additional firm *{blue}* and (authorized) non-firm *{orange}* exports.

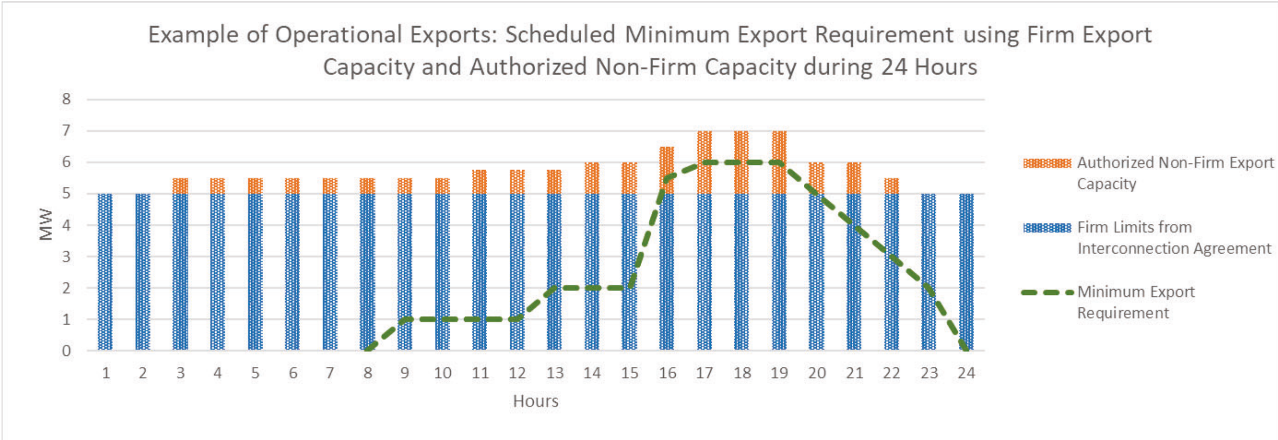

Figure 23: Example of Minimum Export Requirement using Firm Export Capacity

The DER facility may actually export different amounts, so long as it exports at least the required minimum, as illustrated in Figure 24.

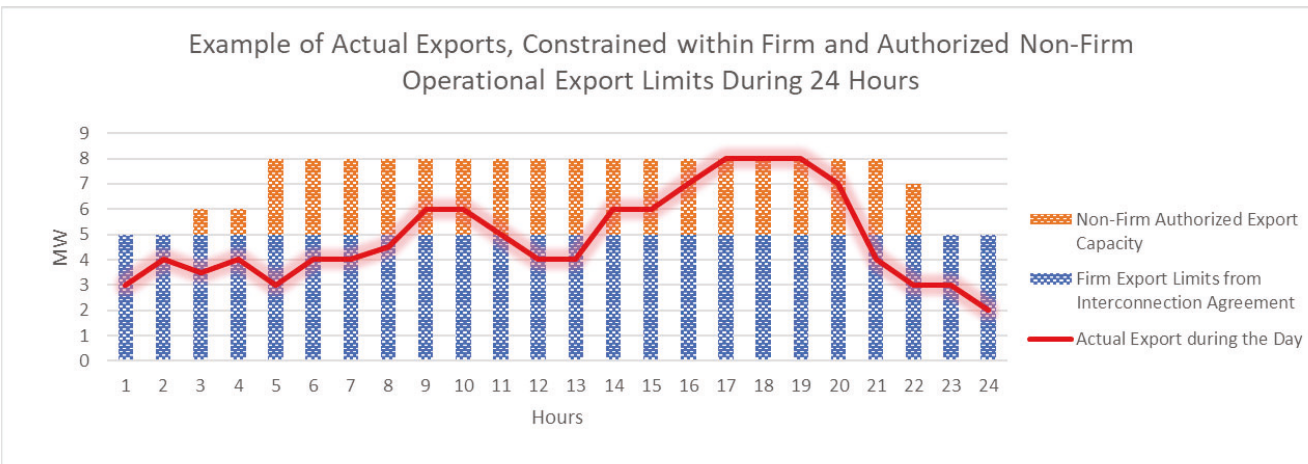

Figure 24: Example of Actual Exports, Constrained within the Operational Export Limits and the Minimum Export Requirements

5.4.4 Use Case 3 Priority Ratings

.As shown in Table 9, these Use Case 3 variations were mostly rated High Priority with different caveats on the possible time they might be implementable.

Table 9: Use Case 3 Priorities for Minimum Generation Export Requirement

Use Case 3 Variations	PG&E	SCE	SDG&E	350BA	CALSSA
Set exact export level at PCC	High Priority: Important, but only for unique situations	High Priority: Technology should/could become available in near-term (3-5 years)	High Priority: even though technology only available in long-term (> 5 to 10 years)	High: Important, but only for unique situations	

Use Case 3 Variations	PG&E	SCE	SDG&E	350BA	CALSSA
Set minimum export level at PCC	High Priority: Important, but only for unique situations	High Priority (: Technology should/could become available in near-term (3-5 years)	High Priority: even though technology only available in long-term (> 5 to 10 years)	High Priority: Technology should/could become available in near-term	High Priority: Technology already available in near-term
Set exact export level at an RPA other than the PCC	High Priority: Important, but only for unique situations	Medium: Important, but not high priority at this time	High Priority: even though technology only available in long-term (> 5 to 10 years)	High: Important, but only for unique situations	High Priority: Technology already available in near-term This is one of the 2-3 most important use cases overall Should be minimum level rather than fixed level Incorrect that aggregators would not be involved. Aggregators control devices. Could be day ahead and could be real time

5.4.5 Use Case 3: Regulatory Issues for Minimum Generation Export Requirements

The regulatory roadmap for Use Case 3, scheduled or commanded Minimum Generation Export Requirements, may involve exploring the addition of the minimum generation export function in an appropriate proceeding. The regulatory issues would involve:

- How could minimum generation export requirements be included in the DSO Interconnection Agreements as schedules and/or as commands. Would "non-firm minimum export requirements" also be included in Interconnection Agreements?
- How would the "minimum generation export requirements" be determined, particularly if/when these requirements become more granular?
- What regulations would be necessary to address short-term and long-term "abnormal" conditions, including what constitutes "abnormal", what are the definitions of short-term and long-term, and what actions DSOs should take to alleviate the "abnormal" condition. For instance, could "abnormal" also include wide-spread or transmission-related power system conditions, such as calls for more generation or less load during heat waves, or notifications of PSPS situations resulting in the formation of microgrids.
- What additional data should be collected to determine whether any contractual resource adequacy requirements were met, particularly during abnormal conditions.
- What communications could be required between the DSO and DER facilities to permit the scheduling of minimum generation export requirements and the updating of those schedules.
- What additional power system monitoring by the DSO might be needed to determine the minimum generation export requirements for real-time commands. How could aggregators be used between the DSO and the DER facilities to relay the commands.

To date, regulations have not addressed the possibility of adding "non-firm minimum generation export requirements" in Interconnection Agreements. It is also clear that actually taking advantage of such flexibility will require the DSOs to have ADMS/DERMS capabilities as well as significant expansions of monitoring the power system. Therefore, it is expected that this Use Case will require significant time and resources to investigate and rule on different aspects.

5.4.6 Use Case 3: SIOWG Participant Consensus, Non-Consensus, and/or Qualifications

5.4.6.1 SCE Consensus, Non-Consensus, and/or Qualifications for Use Case 3

SCE supports this concept with the following qualifications:

- Red line changes proposed are adopted to clarify Use Case A3

5.4.6.2 PG&E Consensus, Non-Consensus, and/or Qualifications for Use Case 3

PG&E supports the concept of generation export minimum requirements with the following qualifications:

- The red line changes are adopted to clarify this use case is only for distribution services and should not be a part of the interconnection agreement or abnormal conditions (outside of a distribution service agreement)
- The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections.
- All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E.
- All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO.
- The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios.
- The DSO does not offer a guarantee for the availability of any non-firm capacity.
- Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations.
- Not all distribution constraints may be able to be mitigated via distribution services.
- For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

5.4.6.3 SDG&E Consensus, Non-Consensus, and/or Qualifications for Use Case 3

SDG&E supports this use case with the caveat that DSOs should have flexibility in negotiating agreements in specific cases to set limits that are consistent with maintaining system reliability and safety in those specific cases. The limits should not become a one size fits all approach.

5.4.6.4 CAISO Consensus, Non-Consensus, and/or Qualifications for Use Case 3

The ISO supports Use Case 3 given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads, and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSEs) along with any export capacity providing grid services to the ISO.

5.5 Technical Assessment of Use Cases 1-3

5.5.1 Entities and/or Systems Involved

In the three use cases identified as high priority for supporting Business Cases A, B, and C, the following entities or systems are involved:

- Utility, including distribution system operators (DSO) and potentially transmission system operators (TSO), who determine what DER constraints and/or support is needed for the grid.
- DSO ADMS/DERMS which includes capabilities for monitoring DER and the grid, as well as applications used to study, schedule, and issue control commands to specific DER or groups of DER. This monitoring and control may be directly with the DER or may be indirect through an Aggregator.
- DSO Planning tools and procedures, which would permit short-term and long-term studies. These tools are needed to determine which DER facilities could be permitted to utilize portions of their non-firm export capacity.
- DER owner and/or operator (e.g., Aggregator, customer) who may permit or reject or modify the requests or commands from the DSO. (*If a request or command is modified or rejected, then the contractual agreements would determine any repercussions.*)
- Aggregator Gateway and Aggregator ADMS/DERMS which includes capabilities for monitoring DER, as well as applications used to study, schedule, and issue control commands to specific DER or groups of DER.
- DER Gateway and Plant Control System which receives and allocates commands from Aggregators and/or DSOs. It may include Facility DERMS (FDERMS) capabilities for managing DER and loads within a facility.
- DER units (generation, storage, controllable load) which receive commands from (authorized) entities.
- DER meters and/or measurement equipment at the Point of Common Coupling (PCC). Meters may need to differentiate services based on compensation by capacity (firm/non-firm). Meters need to meet current standards for accuracy for revenue

Figure 25 illustrates common architectures and interactions between the entities and systems for these Business Cases. The utility {*yellow*} may implement direct control of larger IBR or DER plants {*green*}. The utility EMS and ADMS/DERMS contain applications for studying and managing DER and may include the ability to interact with the energy market. The utility uses a gateway {*orange/brown*} for supporting security requirements while interacting with Aggregators {*red*} and Facilities {*blue*} (including Plant Control Systems) through their gateways. The Aggregators interact either directly with individual DER {*green*}, including electric vehicles, or indirectly via Facility gateways. Facility and plant control systems interact with behind-the-meter DER {*green*}, including electric vehicles. DER owner/operators may interact with the Facility systems and/or with the Aggregator. Typical communications protocols include IEEE 2030.5 {*purple*} (default in Rule 21), IEEE P1815.2 (DNP3 for DER), IEC 61850, and SunSpec Modbus.

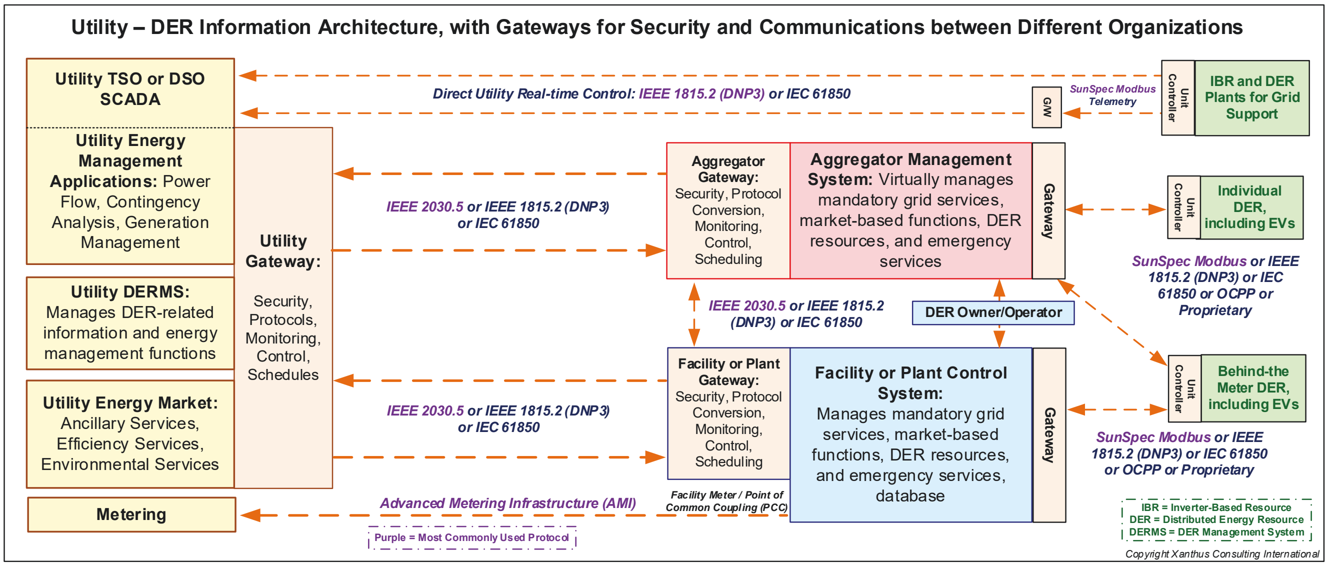

Figure 25: Common Utility and DER Architecture of Entities, Systems, and Communications

5.5.2 DER Functions in Rule 21

The following Rule 21 Tariff functions (which are now aligned with IEEE Std 1547-2018 functions) are involved for DER managing generation export. There are no explicitly defined equivalent functions applicable to loads.

- Function 3 (Limit Active Power command) (Rule 21 Tariff , Section Hh.8.c)
- Potentially Function 2 (Curtailment, Disconnect, Cease to Energize) (Rule 21 Tariff , Section Hh.8.a)
- Function 8 (Scheduling) (also on-going UL 3141 OI effort) (Rule 21 Tariff , Section Hh.6)

5.5.3 Situational Awareness Operationalization Requirements

Operationalization of the Rule 21 Tariff functions requires communications capabilities to provide situational awareness. Currently only DER facilities with aggregate nameplate rating of ≥ 1 MW are required to have telemetry for monitoring facility output, but this telemetry does not include 2-way communications. However, to make the Rule 21 Tariff functions "operational", communications are needed to allow 2-way information flows: monitoring, updating settings and schedules, and initiating direct control (to DER units) or indirect control of DER equipment (via power control systems). As can be seen from Figure 25, such communications involve not only the DSOs, but also the aggregator management systems and the facility power control systems. In certain cases, the DSO may be monitoring and controlling a DER directly.

Four situational awareness operationalization scenarios were identified and assessed. These were:

- Scenario I: DSO collects data from the grid and DER at the PCC within a day, not necessarily with a communications protocol (e.g., could be collected via an Advanced Metering Infrastructure (AMI) system), in order to capture active power export, import, demand, outages, and other data for future analysis.
- Scenario II: DSO collects alarm and event logs from the grid and DER at PCC within an hour, using a communications protocol, to capture data for near-real-time analysis. This analysis may then be used for near-term planning, scheduling updates, or commands.
- Scenario III: DSO monitors the grid and DER export, import, frequency, voltage, and other data at PCC within < 5 minutes, using a communications protocol, for possible use in near-real-time commands.

- Scenario IV: DSO monitors data from the grid and the DER at PCC within one second, using a communications protocol, with the capability to issue real-time commands.

As shown in Table 10, only Scenario III was rated High Priority by all groups as being pertinent to the Use Cases, with slightly different caveats on the possible time they might be implementable. SDG&E rated all of the scenarios as High Priority. There was general agreement that the requirement in Scenario I could be provided by the Advanced Metering Infrastructure (AMI), but there was no agreement on whether AMI data could be useful for distribution services. Such AMI information would also need further effort to be made available in appropriate granularity and format to the ADMS/DERMS functions without violating any privacy requirements.

Table 10: Scenario Priorities for Situational Awareness

Situational Awareness Scenarios	PG&E	SCE	SDG&E	350BA	CALSSA
Data collected within a day (Daily time): AMI Data	Other: (already have AMI for this)	Other: (N/A - Need data at the PoC not PCC)	**High Priority**: AMI technology to record and transmit P, Q, should/could become available in near-term[26]	Other: (already have AMI for this)	Low: Not a high priority at this time
Alarm and event logs from the grid and the DER PCC within an hour (Hourly time)	Other: (would need sub-5-minute monitoring)	Other: (Not sufficiently granular to be of any use)	**High Priority**: Technology should/could become available in near-term	Low: Not a high priority at this time	Low: Not a high priority at this time
Monitoring of grid and DER export, import, frequency, voltage, and other data at PCC within < 5 minutes (Near-real-time)	**High Priority:** Important, but only for unique situations	**High Priority:** Technology already available in near-term (need data in with "seconds" level of granularity")	**High Priority:** Technology should/could become available in near-term	**High Priority**: Technology should/could become available in near-term	**High Priority:** Technology should/could become available in near-term
SCADA-performance monitoring and control of grid equipment and the DER at PCC within one second (Real-time)	Medium: Important, but not high priority at this time	High: Important, but only for unique situations	High Priority: even though technology only available in long-term (> 5 to 10 years)	Medium: Important, but not high priority at this time	**High Priority**: Technology should/could become available in near-term

Situational awareness operationalization requirements may be added to more Interconnection Agreements over time. At this time there is little agreement on monitoring and communications requirements: which power system equipment, which DER systems, how frequently the data is needed, etc. Only DER systems with aggregate gross nameplate ≥1 MW are generally required to have telemetry but not even these systems are required to have two-way communications. Aggregators usually have some form of communications with their DER systems, but this data is not generally available to the DSOs at this time.

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[26] *SDG&E's current AMI technology records interval energy imports and exports (kWh), not instantaneous power flows (kW).*

Situational awareness would improve grid safety, reliability, and capacity management, particularly for monitoring and controlling equipment during abnormal conditions. Without situational awareness the DSO would be flying blind during critical situations.

Situational awareness would improve the ability of DER facilities to provide the needed distribution services by providing near-real-time or even real-time data that would permit the DSO to know more precisely what is occurring on the power grid and to take actions where necessary to correct or improve situations.

In reality, none of the Use Cases supporting Business Cases B and C could be achieved without greatly improved situational awareness. For example:

- **AMI data** could be used for short-term (weekly, daily) assessments of power flows on critical and/or sensitive circuits to determine what conditions should be improved.
- **Alarm and event logs** from the PCCs of DER facilities (large or small) situated in key locations could be used to determine possible or pending abnormal conditions on the grid that would not otherwise be visible to the DSO. Aggregators could also provide this type of information.
- **Monitoring and control in near-real-time** could allow direct or indirect dispatch of commands to mitigate possible problems, as well as to permit additional export or import (see Section 6) of power by DER facilities, particularly during heat waves or other critical situations. Aggregators could provide this service.
- **SCADA-performance monitoring and control** could permit the (authorized) DSO to actively manage certain DER facilities in real-time to improve grid safety, performance, and efficiency.

5.5.4 Information Types of Exchanges

The types of information exchanged for the Use Cases include the following at a minimum:

- **Schedule of firm export limits and non-firm export capacity**. A DSO or aggregator “server” would provide a schedule to the facility gateway, either as a csv file (per UL 1741 SB) or as 24-hourly values by IEEE 2030.5 individual “scheduling” settings. The gateway could either send the entire schedule to the Power Control System (PCS) or send the values one at a time at the point when the scheduled value should take effect. The PCS would then send appropriate commands to the behind-the-meter DER. These commands could be Limit Active Power commands (as per Rule 21 tariff) or could be direct control of DER and/or loads.
- **Monitoring for near-term status and measurements**. Communications capability is included in Rule 21 Tariff, but only required to be implemented for DER facilities with aggregate nameplate ratings ≥ 1MW or for operational engineering reasons. For smaller DER facilities, alternative communication methods might be used. For instance, aggregators typically monitor the DER systems they have installed and/or own, primarily to track outages, equipment failures, and other anomalies. For DER systems that can manage outages by going off-grid, the data at the PCC is available in near-real-time to the aggregators and often to the customers as well. DSOs may be capable of receiving this aggregator data for small DER facilities (<1 MW) depending upon contractual arrangements.
- **Commands for limiting exports**. In Rule 21 Tariff , Section Hh.8.c, Limit Active Power is the export limiting command to the RPA. However, as noted above, implementation of communications may be restricted to the larger DER facilities or may go through the aggregators.

- **Metering for after-the-fact validation**. AMI systems provide revenue-grade energy data, and most include demand data. This data is usually only available after 1 day, so it is not typically available in real-time or near-real-time.

5.5.5 Communication Protocol Issues

Four protocols are identified as possible for supporting scheduling, commands, and near-real-time monitoring. These include:

- **IEEE 2030.5** is the default communication protocol in Rule 21 Tariff and its implementation was codified in the IOU-developed Common Smart Inverter Profile (CSIP) of March 2018. IEEE 2030.5/CSIP meets Rule 21 Tariff requirements for managing aggregator, gateway, and DER's power, reactive power, and configured curves and settings. The protocol supports two different control modes: Scheduled events that includes a start time and duration; and Default controls that are permanent unless overwritten with a Scheduled event or another default control. Scheduled events can be set to start in the future or upon receipt (start time = now). Default controls always start upon receipt. IEEE 2030.5/CSIP also supports receiving DER information such as telemetry and status as required by Rule 21 Tariff. A new version of IEEE 2030.5 is expected to be published at the end of 2023/Q1 2024 and includes IOU requested functionality supporting SIOWG use cases including import limits and microgrids, as well as further enhancements. CSIP will need to be updated accordingly, as well as to correct errors and omissions from the current 2018 version.
- **IEEE 1815 (DNP3)** is used by most DSOs for SCADA interactions with field equipment. **IEEE P1815.2 (DNP3 profile for DER)** has added the IEC 61850-7-420 data model to DNP3 and so does include a full scheduling capability, command capability, and real-time monitoring capability that could be used to meet all of the Use Cases identified in Business Cases A, B, and C. Its predecessor, MESA-DER and the DNP3 Application Note, 2018-001, is included in IEEE Std 1547.1 testing requirements and has been implemented with scheduling, commands, and monitoring by a number of DER vendors for larger DER plants that are monitored and controlled by DSOs. It is currently being transitioned to an international standard as IEEE P1815.2 and is expected to be balloted in Q1 2024.
- **SunSpec Modbus** is primarily focused on device-level communications, and, with a few exceptions, is not expected to be used by DSOs for direct communications with DER facilities.
- **IEC 61850-7-420** is the information model used as a basis for all the other DER protocols, although adjustments have been made to accommodate protocol-specific characteristics. Natively, IEC 61850-7-420 data runs over IEC 61850-8-1 (client-server) or IEC 61850-8-2 (XMPP publish-subscribe). A third IEC 61850 protocol, GOOSE (including routable GOOSE or R-GOOSE), can be used for very high-speed interactions, such as with protective relays. Although not often used in the US for DER, IEC 61850 is the communications standard that is expected to be used world-wide.

For schedules that are included in interconnection agreements (see Business Case A), UL 3141 will include a csv-formatted schedule that can meet all of the scheduling requirements. This csv-formatted schedule could be used in place of IEEE 2030.5 by having the facility gateway or PCS download it via the internet from an appropriate "server" site.

5.5.6 DSO ADMS/DERMS Capabilities/ Applications

The DSO DER management systems (DERMS) need to include many analysis capabilities to support the requirements of Business Cases A, B, and C. These could include the following:

- Information on the historic generation and load profiles of DER facilities.
- Information on static and dynamic attributes of DER facilities and their associated control systems

- Modeling of all DERs and their functional abilities, in relevance to DER management and control
- Availability, performance metrics of all DERs to establish baseline and risk factors associated with relying on DERs during abnormal/normal situations
- Information on grid Interconnection Agreements for DER facilities, including any scheduled export limits.
- Power flow applications that can be used to model the power system in study mode and in near-real-time mode. These applications, similar to those used for transmission power systems, but applicable to distribution grids, include state estimation, contingency analysis, study mode analysis, etc. These applications would be used for distribution services such as identifying potential near-term and future problems, determining which aggregators and/or DER are contractually required to perform which services (e.g., limit export), and providing incentives for other aggregators and/or DER to provide other services.
- Hosting capacity analysis that can assess dynamic hosting capacity at each nodal level to be able to assess export/import limits and flexibility around these limits. The analytical method may differ from the methods used in ICA given its more operational nature.
- Near-real-time monitoring of the grid to determine whether existing services are still needed or can be adjusted to reflect current conditions.
- Updating of existing schedules of export limits to reflect the power system analyses, including authorization of Non-Firm export capacities.
- Communications capabilities to provide schedules, commands, incentives, and other information to specific DER facilities, aggregators, and/or VPPs.
- Communications with aggregators to acquire certain types of data for improving situational awareness to enhance grid safety, reliability, and efficiency.

It is expected that DSO ADMS/DERMS are already designed to have the ability to collect and use DER facility information and to perform power flow assessments. However, their implementation timetables may vary between DSOs, as will their detailed capabilities.

Also, due to the natural focus of these ADMS/DERMS on managing DER, either directly to individual DER or indirectly through instructions issued to aggregators, some of these DSO system may not have the ability to manage loads. The Use Case C4 on limiting imports (load) is based on the expectation that electric vehicles, electric stoves, electric heat pumps, and other electrification of systems will grow significantly over the next years, and that managing (limiting, controlling, and shedding) loads will become increasing critical for a safe and reliable grid. Therefore, the ADMS/DERMS or other DSO systems will need to provide similar support for managing imports, including the authorization of Non-Firm import capacities.

Additionally, situational awareness requirements have identified the need for near-real-time communications (within 5 minutes) between DSOs and DER facilities, either directly or indirectly. Because of the expense of requiring the smaller (< 1 MW) DER facilities to include such communications capabilities, the DSO ADMS/DERMS may not have been designed to handle such communications. However, it could be possible to acquire that data from some aggregators.

Therefore, these types of ADMS/DERMS capabilities may require additional time by DSOs to design and implement the appropriate systems.

5.5.7 Aggregator DERMS (ADERMS) and/or Facility DERMS (FDERMS) Capabilities/ Applications

The Aggregator DERMS (ADERMS) and/or the Facility DER Energy Management System (FDERMS) need to include additional capabilities to support the requirements of Business Cases A, B, and C. These capabilities include:

- Monitoring and control capability of behind-the-meter DER units and controllable loads.
- Monitoring of the net active and reactive power of DER and load at the PCC.
- Managing groups of DER systems, including VPPs.
- Receiving updates to Limit Active Power and load schedules, as well as limit commands.
- Monitoring of voltage and potentially frequency at the PCC if distribution services could involve voltage or frequency functions.
- Assessing the export of active power at the PCC to determine whether it remains within the limits needed to meet the DSO's distribution service requirements.
- Providing near-real-time data as required by the DSO to support the distribution services.
- Handling of failure and error conditions to ensure failsafe responses to abnormal situations.

These ADERMS and FDERMS system capabilities will require time to design and implement, similarly to the DSO ADMS/DERMS systems and planning tools.

It is understood that Aggregator ADERMS and Facility FDERMS have many additional capabilities, for instance, to perform energy arbitrage, but those capabilities are not covered here.

5.6 Challenges for Use Cases 1-3

Use Case challenges include issues, such as the possible impact on the design and capabilities of DSO ADMS/DERMS and requirements for communications, that may affect the timing of deployment as well as the financial impact on DSOs, DER aggregators, and DER owner/operators. Table 11 identifies the primary challenges for the Use Cases 1-3, which cover the different requirements for active power export limits as a distribution service.

Table 11: Use Cases 1-3: Management of Active Power Export

Use Cases	Management of Active Power Export
Challenges	
DSO challenge: DSO use of ADMS/DERMS study applications to determine settings, schedules, and affected DER	DSO ADMS/DERMS and the various planning tools are, for the most part, not yet capable of performing the power flow studies to determine what the schedules and Firm Export limits and Non-Firm export capacities would need to be for formal inclusion in Interconnection Agreements.
DSO and DER owner/operator challenge: Coordination between Rule 21 Tariff and revisions to IEEE Std 1547	Scheduling is in Rule 21 Tariff (although not yet required to be implemented) but it is not yet in IEEE Std 1547. It may be added during the revision, thus leading to possible delays in determining what scheduling capabilities should be included for California DSOs.
DSO and DER owner/operator challenge: Updating UL 1741 for safety and functional issues	An effort is already underway to provide clarifications in UL 1741 for developing a simple Limit Active Power schedule (csv file). In addition, if schedules are just handled manually and provided in the interconnection agreement, there would be no impact on UL 1741. A new Outline for Investigation, UL 3141, for Power Control Systems (PCS) (a basic type of FDERMS) is being developed. However, UL does not yet support the concept of Operational Export Limits consisting of Firm Export plus any additional authorized Non-Firm capacity.

Use Cases	Management of Active Power Export
Challenges	
DER owner/operator challenge: Updating software/firmware for DERs	The export limit capability is already included in Rule 21 Tariff and is being tested in DER units through UL 1741 SB, but few DER units have been formally tested through UL 1741 for scheduling. IEEE 2030.5, IEEE 1815.2 (DNP3), and SunSpec Modbus protocols could be used to transmit schedules. The concept of Operational Export Limits, consisting of Firm Export plus any additional authorized Non-Firm capacity, would also have to be implemented. In addition, UL is developing a spreadsheet approach to scheduling in UL 3141 OI. Regardless of the protocol used to transmit the schedules, the implementation of schedule management for Firm Export limits could require major software upgrades, particularly if implemented in DER units rather than in an ADERMS or FDERMS. Use of Non-Firm export capacity, when authorized by the DSO will also need to be implemented. As a note (not included in the assessment value), manufacturers could have significant additional costs for implementing a complete scheduling capability (beyond Limit Active Power) , so the implementation of the simple scheduling capability is expected to be less than the eventual requirements. Scheduling may also be included in the revision to IEEE Std 1547-2018.
DER owner/operator challenge: Updating software/firmware for facility FDERMS or aggregator ADERMS (gateway platforms)	If Operational Export limit scheduling is implemented in the DER Facility FDERMS rather than in the DER system, then the impact on the DER is minimal and most of the impact would be in the FDERMS. However, even for the simple scheduling version, the FDERMS would need to validate and issue the schedule. The FDERMS could also potentially analyze the Firm Export limit schedule and allocate different settings or limits to different DER units while still resulting in the required Limit Active Power at the RPA.
DER owner/operator challenge: Type testing for new capabilities	DER and/or the FDERMS would need testing for scheduling of Limit Active Power. The degree of challenge could depend on how and where the scheduling is performed.
DER owner/operator challenge: Deploying updates to field equipment	The scheduling of Limit Active Power would need to be deployed to field equipment. The degree of challenge could depend on how and where the scheduling is performed.
DER owner/operator challenge: Site testing	Site testing of the scheduling of Limit Active Power in the DERMS/DER combination would need to be undertaken. The degree of challenge could depend on how and where the scheduling is performed.
DSO and DER owner/operator challenge: Communication impacts during operations	If the UL 3141 csv files are used for schedules, such as for LGP schedules or distribution services schedules, then only access (probably via the Internet) to the location of the files is needed. However, additional communications capabilities may be needed to collect event logs and measurement data for validation purposes. These event logging requirements have not been defined at this time. Variations in export limits can impact and frustrate customers when adequate information is not readily available in a timely manner, either before or during transitions between export limits.

Use Cases	Management of Active Power Export
Challenges	
DSO and DER owner/operator challenge: Cybersecurity for at-rest and in-transit information over communications networks	Cybersecurity requirements will vary significantly depending on how schedules are provided to DER, including updates to schedules. If they are just posted on a web site for downloading, then web-level cybersecurity would be needed. If actively sent to DER, then the cybersecurity of the communication protocol(s) used for the end-to-end transmission would need to be included.

6 Use Case 4: Operational Flexibility in Import Limits and Non-Firm Import Capacity

6.1 Overview of Import Use Case Issues

Use Case 4 is similar technically to Use Cases 1 through 3 except that the electrons (current) are going in the opposite direction (load versus generation). Just like those Use Cases, Use Case 4 can also support Business Cases A, B, and C. However, it is covered separately in this document since the historical and regulatory issues are significantly different due to the current regulatory structure as well as the regulated DSO service obligations with respect to load. Simply put, regulated utilities have an "obligation to serve" which means that they have to accommodate all customer loads and are obligated to provide the grid capacity necessary to deliver the power that serves those loads, whether from the transmission system or from DER within the distribution system. DSOs may request time to implement system upgrades and may limit loads during that time, but they are eventually obliged to provide the capacity for the load.

Who pays for any system upgrades is a regulatory issue which is out-of-scope of the SIOWG, but if the DSO is obligated to pay, then these payments can affect ratepayers. Minimizing these costs while still meeting all obligations will be increasingly important in the future. For comparison, with certain exceptions, such as DERs <1 MW taking service under a Net Energy Metering (NEM) Tariff , DER facilities interconnecting at the distribution level are currently required to pay for the costs of the grid improvements that the DSO's interconnection studies determine are necessary to safely and reliably interconnect the generator. However, grid improvements that accommodate customer loads are generally paid for by all ratepayers, not by the customer requesting load service. This makes the regulation of loads (import into a facility) different from generation export from a facility with respect to limiting import power and the obligation to pay for grid improvements.

In California, DER interconnections at the distribution level are handled by Rule 21 Tariff which is evolving to address new DER requirements, including the scheduling of DER export limits (see Section 5.2). Load, on the other hand, is addressed by Rule 2 (voltages and kVA provisions), Rule 15 (Tariff for distribution line extensions), and Rule 16 (Tariff for service line extensions). There is no formal definition of Limited Load Profiles similar to Interconnection Agreements used by the DSOs. These load-related tariffs do not address load limits, but rather use pricing to attempt to shape loads. The DSO Tariffs are based on time-of-day structures to incentivize customers to decrease loads during "on-peak" times while "Demand Response (DR)" programs ask customers to react to financial or reliability signals. DR is sometimes viewed as the only or best way to handle loads. As stated by the CPUC[27], "*DR traditionally involved customers reducing electricity consumption temporarily in response to economic or reliability signals. More recently, DR has evolved to encourage customer to shift electricity consumption from hours of high demand relative to energy supply to hours where energy supply is plentiful relative to demand. Future DR may involve customers* **increasing** *their electricity usage when the grid has too much electricity generation from renewable resources like the wind or sun*."

[27] *https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr#:~:text=Effective%20demand%20response%20programs%20provide,lowering%20overall%20cost%20of%20electricity*

However, at this time, *no specific steps have been taken to contractually **limit load imports**, either by schedules or by commands* except temporarily if the customer doesn't want to wait for the DSO to upgrade the distribution system. From a regulatory perspective, managing firm and non-firm import requirements is different from managing the export requirements. Because of the DSO's obligation to serve, loads have always been seen as mandatory requirements that must be met, even if it might take some time to upgrade the distribution system. However, a large increase in the use of electricity is expected as customers move away from gas stoves, gas heating, and gas cars, and move toward electric stoves, electric heat pumps, battery storage systems, and electric vehicles. It would therefore be beneficial to determine regulatory methods for responding to this increased electrical demand, particularly if it is combined with the increased implementation of DER.

In the High DER Future, it is expected that loads will also have to be managed more proactively due to the increased electrification of equipment and to the increased controllability of many loads, specifically those associated with charging DER storage and EVs. For this reason, the term "Limited Load Profiles" are introduced to act a parallel agreements to Interconnection Agreements. Use Case 4 looks at some of the comparable issues for loads as were identified in Use Cases 1-3 for generation.

Use Case 4 addresses providing flexibility through the use of firm and non-firm limits for handling import (loads) in Limited Load Profiles. This Use Case is complex because of regulatory issues related to load regulations, including the DSO "obligation to serve." However, as more electric vehicles and other types of electrified equipment (stationary batteries, electric stoves, water heating, home heating) are connected to the grid, the capacity of the grid could be strained by these loads. However, many of these loads, particularly charging of stationary storage and electric vehicles, are capable of flexibility:

- When the import of power takes place (minutes, hours, days).
- The rate of import of power (slow charging, fast charging, intermittent loads).
- The length of time the load can be curtailed (minutes, hours, days).
- The degree of controllability (dependencies on other factors, such as ability to pre-heat or pre-cool, facility temperature, percent charged, emergency preparedness).
- The ability of the loads to provide grid services (ride-through, voltage support, time-based charge/discharge, use of schedules).
- These rules and standards should include the capabilities of DER communication and control to manage and/or shift controllable load as well as DER generation.
- If Virtual Power Plants (VPPs) have either direct control or demand response capabilities, the DSO can request or require (if contractually agreed) the VPPs to limit load (see Business Case F on Community Microgrids).
- The CPUC Rules 2, 15, and 16 address building power extensions to support new loads, but do not address any issues related to "smart loads", such as charging EVs or storage systems. Policies and rules related to such "smart" controllable load should commence development since these types of polices and rules often take years to be developed, and therefore should be started as soon as possible.

6.2 Import Use Case 4 Supporting Business Cases A, B, and C

6.2.1 Use Case A4: Firm Import Limits and Non-Firm Import (Load) Capacity in Limited Load Profiles

Use Case A4 addresses the (optional) inclusion of firm import limits and non-firm import capacity in Limited Load Profiles. It covers all three aspects of Use Cases 1, 2, and 3 because those aspects are fully covered in those descriptions and repeating them for loads is therefore not necessary except to state:

- The Limited Load Profile includes the ability of the DSO to establish a schedule of **firm import limits** and additional **non-firm import capacity**, measured at the PCC. This is the equivalent to the Use Case A1 for scheduling export limits but applies to import limits.
- The Limited Load Profile includes the ability of the DSO to issue commands to authorize the use of additional **non-firm import capacity** at the PCC, and if needed for abnormal conditions, to modify the **firm import limits**. This is the equivalent to the Use Case A2 for commanding generation export limits but applies to load import limits.
- The Limited Load Profile includes the ability of the DSO to request a **minimum firm** or **non-firm import amount,** either through schedules or commands. This is the equivalent to the Use Case A3 for minimum generation export requirements but applies to load import requirements.

Figure 26 illustrates a typical **firm import limit** and **non-firm additional import capacity** in a Limited Load Profile.

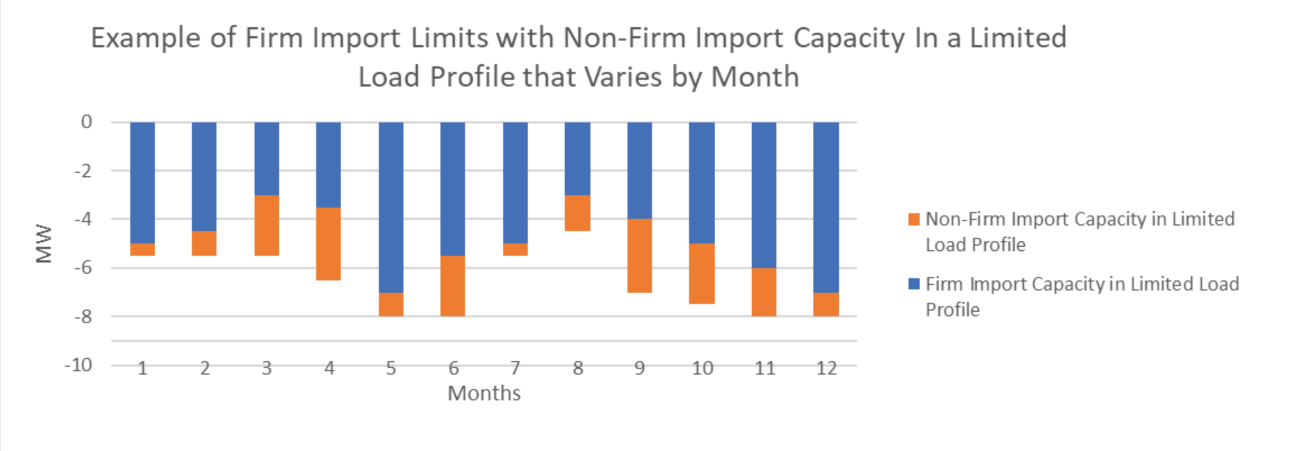

Figure 26: Firm Import Limit and Non-Firm Additional Import Capacity in a Limited Load Profile

6.2.2 Use Case B4: Firm Import Limits and Non-Firm Import (Load) Capacity Before or During Abnormal Conditions

Use Case B4 addresses the scheduling and/or commands for firm import limits and non-firm import capacity before and during abnormal conditions.

This Use Case will become increasingly important as more electric vehicles and stationary storage systems charge from the grid. During abnormal conditions, both DER charging, EV charging, and other ***controllable*** loads may need to be curtailed to mitigate reliability issues and/or to avoid outages. Therefore, the DSO ADMS/DERMS capabilities should include commands and/or schedules to manage these abnormal conditions:

- The ADEMS/DERMS would issue commands and/or updates to schedules to invoke import curtailments for planned, forecast, and emergency conditions:

- If the emergency abnormal condition is not perceived by the DER facilities (e.g., due to being on a separate circuit), a command could be sent to limit import (including down to zero import).
- Planned or forecast abnormal conditions could involve sending a schedule of limits for the firm import and/or rescinding the permission for using non-firm import capacity.

- Although most abnormal conditions could involve limiting import during the situation, it may be beneficial to permit additional non-firm load during the recovery phase after the abnormal condition has been resolved.

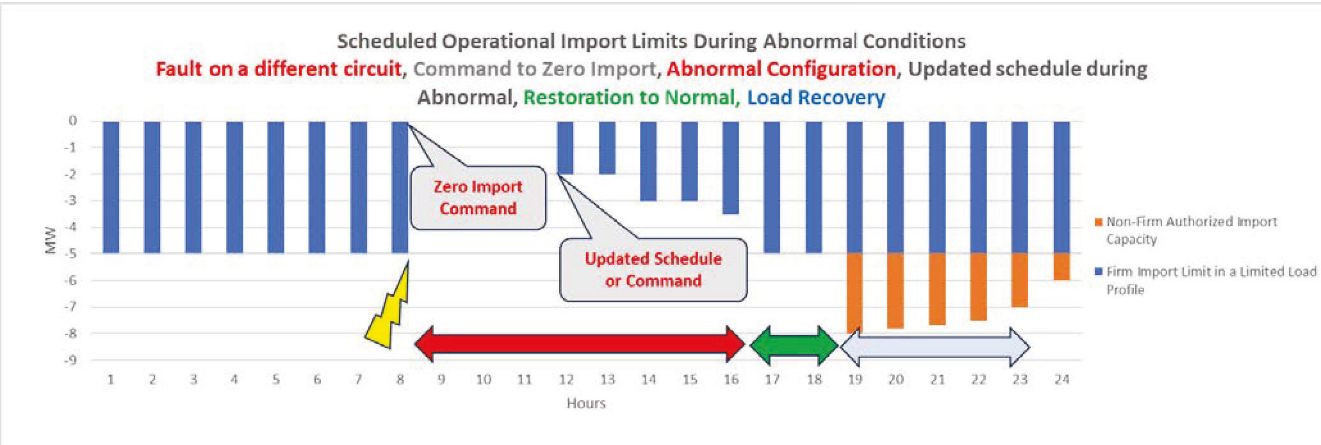

Figure 27: Firm Import Limits and Non-Firm Import Capacity during Abnormal Conditions

6.2.3 Use Case C4: Firm and Non-Firm Import (Load) Limits for Distribution Services

Use Case C4 also addresses the ability for controllable loads to provide DER services. As discussed in Business Case C, these DER services could benefit the DSO but also the ratepayers, CAISO, DER owner/aggregators, and society.

Once the ADMS/DERMS and communications capabilities are able to identify potential grid services to improve reliability and efficiency, then the controllable loads could provide these distribution services based on contracts or other incentives. These distribution services would support the goals of Business Case C, including:

- Authorizing the additional use of non-firm capacity via schedules that may have different time periods from the load time-of-use Tariffs, which would be the usual method of influencing loads. For instance, the use of non-firm import capacity could be authorized during low load conditions at night or during weekends.
- Use of non-firm import capacity could be matched to DER export if the generation and load could “follow” each other. As an example, the generation from one DER facility could “follow” the load of a large truck or bus charging station on the same circuit to offset the extra load, but if the generation is not adequate, then the non-firm load could decrease.
- Commanded changes in the use of non-firm capacity could help meet reliability and efficiency requirements, by the DSO issuing commands to reduce non-firm imports in order to avoid thermal overloads and/or voltage anomalies.
- Scheduled or commanded minimum firm or non-firm load imports. These distribution services to increase load would be the alternative side to demand response which seeks to decrease load. The purpose would be to help manage the time when loads occur. Although not seen today at the distribution level, some examples of future use could include:

– To offset excess generation from renewable resources (solar and/or wind) and thus not "waste" that potential energy.
– To charge DER storage and EVs at night during the normally low load periods, in order to utilize excess power from wind turbines even if Tariffs are not specifically designed to incentivize those actions.
– To charge DER and EVs by solar systems during the morning and mid-day hours to minimize the charging load in late afternoon or early evening, particularly if heat waves are expected to cause power availability problems or very high locational marginal prices.
– In community microgrids, to manage load as well as generation to meet microgrid reliability, sustainability, and equitability requirements.

Figure 28 illustrates operational import limits with granular authorized non-firm import capacity over 24 hours.

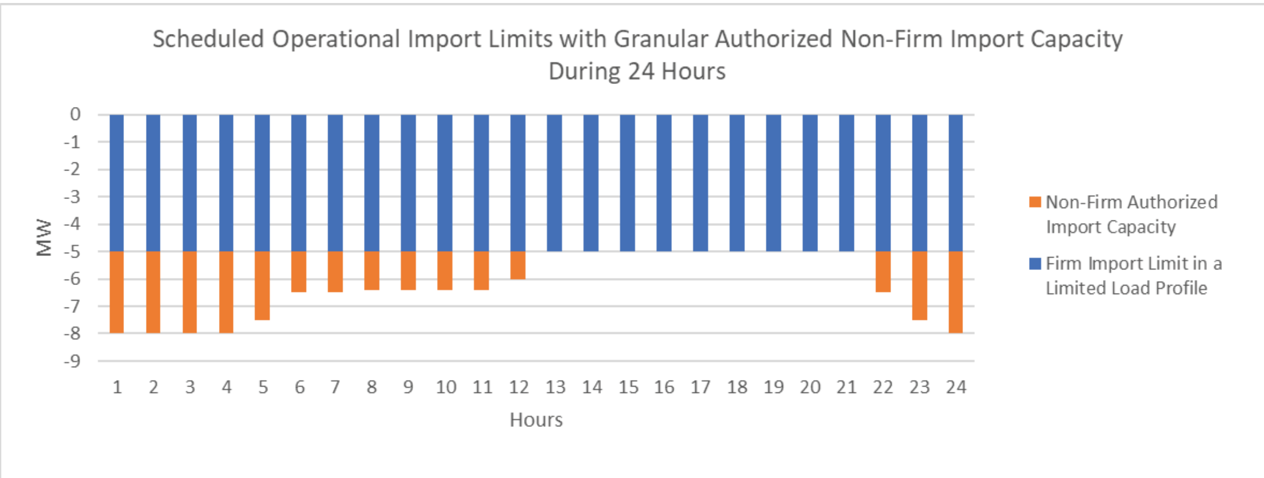

Figure 28: Operational Import Limits with Granular Authorized Non-Firm Import Capacity over 24 Hours

6.2.4 Use Case 4 Priority Ratings

As shown in Table 12, the Use Case 4 capabilities were rated mostly High Priority with different caveats on the possible time they might be implementable.

Table 12: Use Case 4 Priorities for Commanded Maximum Export Limit

Use Case 4 Variations	PG&E	SCE	SDG&E	350BA	CALSSA
Schedule for maximum import (load) limits	High Priority: Technology should/could become available in near-term	High Priority: Technology should/could become available in near-term (3-5 years)	High Priority: Technology should/could become available in near-term	High Priority: Technology should/could become available in near-term	Medium: Important, but not high priority at this time

Use Case 4 Variations	PG&E	SCE	SDG&E	350BA	CALSSA
Command to set the maximum import (load) limit	High Priority: Technology should/could become available in near-term	High Priority: Technology should/could become available in near-term (3-5 years)	High Priority: even though technology only available in long-term (> 5 to 10 years)	High Priority: Technology should/could become available in near-term	"Ability to connect faster without waiting for system upgrades to be completed" is an interconnection use case, not a grid service. This is only useful as a grid service if there is a compensation program. The same value to the DSO can be achieved with commanded storage discharge (C3c)

6.2.5 Use Case 4 Regulatory Issues for Firm Import Limits and Non-Firm Import Capacity

The regulatory roadmap for Use Case 4, Maximum Import Limits, may involve significant efforts related to Rule 2, Rule 15, and Rule 16. In addition to the types of issues related to export limits, the regulatory issues for import limits could involve:

- Since the concept of firm import limits and non-firm import capacities, whether scheduled or commanded, have not previously been addressed, this effort could require significant discussions with impacted stakeholders. For instance, would consumers, particularly large commercial or industrial consumers such as truck charging stations, be willing to cope with schedules which varied their non-firm imports at certain times?
- Regulatory proceedings would have to determine many of the details related to the scheduling of non-firm import capacity. It is unclear which existing proceeding(s) might be affected and which new proceedings might be required.

6.2.6 Use Case 4: SIOWG Participant Consensus, Non-Consensus, and/or Qualifications

6.2.6.1 SCE Consensus, Non-Consensus, and/or Qualifications for Use Case 4

SCE supports this concept with the following qualifications:

- Discussion should be had on whether DSO having the ability to reduce the load constitutes a grid services. Perhaps it is via a special rate as opposed to a PPA.
- It may be necessary to introduce a new rule that combines Generation DERs and flexible load DERs.
- Red line accepted or discussed for alignment.

6.2.6.2 PG&E Consensus, Non-Consensus, and/or Qualifications for Use Case 4

PG&E supports the concept of applying firm import limits and non-firm import capacity for DERs with the following qualifications:

- The DSO must have the planning tools available to determine reasonable firm and non-firm limits in advance for inclusion in the interconnection agreements.

- The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections.
- All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E.
- All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO.
- The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios.
- The DSO does not offer a guarantee for the availability of any non-firm capacity.
- Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations.
- Not all distribution constraints may be able to be mitigated via a flexible connection.
- For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

6.2.6.3 SDG&E Consensus, Non-Consensus, and/or Qualifications for Use Case 4

Conceptually, limiting or controlling grid withdrawals can provide distribution services. For example, an aggregator could contract with customers with electric vehicles and, for some form of compensation paid to the customers, manage their electric vehicle charging in a manner which allows the utility to cost-effectively defer planned distribution infrastructure. The utility would compensate the aggregator provided the aggregator responds appropriately to the DSO's dispatch instructions. This is the model for the Partnership Pilot. Importantly, this model presumes voluntary participation by customers. SDG&E does not support Use Case 4 to the extent it assumes involuntary participation by customers. Customers should have the freedom to consume, or not consume, based on their personal preferences and economic incentives.

6.2.6.4 CAISO Consensus, Non-Consensus, and/or Qualifications for Use Case 4

The ISO supports Use Case 4 given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads, and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSEs) along with any export capacity providing grid services to the ISO.

7 Business Case D: Operational Flexibility through Voltage Support by DER

7.1 Business Case D Overview

Business Case D addressed voltage support by DER but it was not identified as high priority, so no use cases were developed for possible voltage support distribution services. Currently the volt-var function and the volt-watt functions are in Rule 21 Tariff and could be used if requested by the DSO, so no additional operationalization capabilities were identified.

7.2 Business Case D in the Future

However, if during the assessment of Business Cases A, B, and C, the ability and need to manage voltage support via schedules and commands becomes more evident, Business Case D could be revisited. For instance, schedules for Volt-Var and/or Volt-Watt support could be provided by the DSOs to certain DER facilities to provide voltage support for energy efficiency.

7.2.1 Business Case D: SIOWG Participant Consensus, Non-Consensus, and/or Qualifications

7.2.1.1 350 Bay Area Consensus, Non-Consensus, and/or Qualifications for Business Case D

Business Case D (Voltage Support) was not identified for priority SIO opportunity but offers potential for significant additional use of Conservation Voltage Regulation to realize 1-2% efficiency savings across all areas in which they are employed. Voltage drops over distance and must be boosted at the regulating device in order to ensure that it falls within established parameters further "downstream" from the energy source, including with DER sources and bi-directional power flow on the lines. Using SIO at intermediate locations enhances operational voltage efficiency.

8 Business Case E: Operational Flexibility for Electric Vehicles Providing Distribution Services

8.1 Business Case E: Description

Business Case E addresses the capabilities and potential requirements for Electric Vehicles (EVs) to provide distribution grid support services while charging and/or discharging (V2G), similar to those provided by grid-connected DER, as discussed in Use Cases 1-4. Although similar, the ability of electric vehicles to provide grid services has many differences from stationary DER due to their roaming capability, driver decisions that are not related to energy or price, and the proprietary EV Original Equipment Manufacturer (OEM) testing and certification requirements that are separate from any testing and certification of Electric Vehicle Supply Equipment (EVSE).

This Business Case E reviewed the potential distribution grid support services that could be provided by EVs to determine which were deemed the highest priority, based on practical issues such as the capabilities of current EV and EVSE engineering designs, timeframe for EV manufacturers to provide those capabilities, and the degree of need for specific grid services. Also considered were the impact of large numbers of EVs charging on the grid, whether they were a managed fleet of EVs or uncoordinated individual EVs on the same feeder.

Although the functional capabilities may be similar, this Business Case does not address vehicle to home (V2H) services but only vehicle to grid.

8.2 Business Case E: Purpose to Solve Problems or Provide Opportunities for Different Stakeholders

Business Case E identifies the reasoning and justification for asking or requiring EVs to provide certain distribution grid services, both during abnormal conditions and during normal conditions.

Although EVs have batteries and inverters like stationary energy storage systems (ESS), their fundamental purpose is to provide transportation, not grid services. However, they typically spend large percentages of their time parked and connected to the grid through chargers termed Electric Vehicle Service Elements (EVSEs) and could provide grid services at those times, so long as they were ready (adequately charged) when needed by their drivers.

The purposes of the EV distribution grid services fall into the following categories:

- **Minimize the impact on the grid** of many EVs charging simultaneously, such as potential thermal overloads or voltage sags. These EV services can make use of the Rule 21 Tariff functions for any electric vehicles deemed to be "DER", but that currently only involves V2G vehicles that are discharging. Use Case 4 addresses this issue.
- **Provide benefits to the grid** by improving grid safety, reliability, and efficiency, such as participating in frequency and voltage ride-through events, providing voltage support, and in aggregate, providing frequency support to the transmission system. Currently Rule 21 Tariff functions (Section Hh) are applicable to V2G vehicles capable of discharging, but V1G vehicles that are charging could also provide these benefits, as per Use Case 4.
- **Provide benefits to EV owners**, such as acting on incentives for providing certain grid services that could improve grid reliability and efficiency.
- **Provide societal benefits**, such as providing alternatives to grid services that would otherwise need to be provided by fossil fuel generators.

8.3 Business Case E: Justifications and Benefits for Stakeholders

Business Case E addresses the justifications and benefits to the DSOs and the EV owners for the ability of EVs to minimize their impact on the grid and to provide certain services to the distribution grid.

The charging of EVs (V1G) could impact the safety and reliability of the grid by the simultaneous charging of EVs at specific times of the day, and because, unlike normal loads which are associated with fixed locations, EVs can change where they charge dynamically. Rule 21 Tariff only includes EVs while charging if they are possible participants in the Emergency Load Reduction Program (ELRP) proceeding (R.20-11-003, A.22-02-005). The benefits of flexible import limits are discussed in Business Cases A, B, and C, as well as more explicitly in Use Case 4 (see section 6). Business Case E addresses the benefits of managing EV controllable loads and using their inverter capabilities to provide grid services for both abnormal and normal grid conditions.

The discharging of EVs (V2X) is still in its infancy. However, the CPUC definition of DER includes EVs that can discharge, so V2G is included as a type of DER in Rule 21 Tariff. Therefore, they must comply with the Rule 21 Tariff generation requirements. Rule 21 Tariff allows the interconnection of V2G EVs using DC discharging, and UL 1741 SC (based on SAE J3072) is currently developing the testing requirements for V2G EVs using AC discharging.

Although IEEE Std 1547-2018 does not directly address fixed storage (much less EVs) while charging, it is clear that both charging and discharging EVs could provide many grid services, and may, in fact, become required by regulations, by contract, or by incentives to do so in the future. Therefore, this raises the question on whether the functions in Rule 21 Tariff and/or IEEE Std 1547-2018 should be extended to charging as well as discharging. That discussion is taking place in the groups working on the revision to IEEE Std 1547.

Table 13 identifies justifications and benefits for stakeholders for Business Case E, where V1G and V2G EVs (paired with capable EVSEs) can minimize their impact on the grid and may provide DER-type services to the distribution grid.

Table 13: Justifications and Benefits V1G and V2G EVs and EVSEs for Stakeholders for Business Case E

Business Case E Justifications and Benefits	Description of Specific Justifications and Benefits
DSO benefit: Operational safety to minimize personnel harm and equipment damage	EVs are expected to increase the overall load on distribution grids by significant amounts over the next few years, particularly in California. Excessive active power flows from these loads can cause thermal overloads over short or long terms. These thermal overloads can harm equipment, including degrading their lifespan and causing failures. Failed or degraded equipment can potentially cause safety issues. If EVs and EVSEs can have incentives (Tariffs, contracts, demand response pricing) and/or mandatory requirements for limiting some charging aspects, such as rate of charging and time of charging, then DSOs will benefit from avoiding or minimizing the possibility of thermal overloads.
DSO benefit: Operational reliability to minimize power outages	EVs can charge from different EVSEs at different locations. If external events (such as storms or social events) cause large numbers of EVs to charge in unexpected locations or amounts, this could potentially cause voltage and/or thermal overload contingencies. If EVs can have incentives and/or mandatory requirements for limiting some charging aspects, such as rate of charging and time of charging, then DSOs will benefit from avoiding or minimizing the possibility of these voltage or thermal overloads.
DSO benefit: Operational flexibility to meet reliability and efficiency goals through timely response to situations	In addition to minimizing their impact from charging, EVs could be beneficial to DSOs by responding in real-time (seconds) or near-real-time (minutes) to grid conditions. These responses could be autonomous, such as responding to frequency or voltage deviations, or could be requested/commanded by DSO through aggregators. For example, DSOs could request EVs which are capable of discharging (V2G) to provide additional generation during emergency conditions
DSO benefit: Operational flexibility of capacity to meet renewable energy goals and DSO savings from deferring construction costs	EVs, by using electric power rather than fossil fuel power, help to meet renewable energy goals – if the grid power for charging them comes at least in part from renewable energy sources. "Increasing capacity" is currently viewed more as a DER generation issue (supporting the exporting of power back to the grid) since loads have in the past been the determining factor for upgrading the distribution grid. However, eventually "capacity" of the grid will include both generation and load as factors. Again, managing EV charging and discharging (V2G) will help defer construction by the DSO.
CAISO benefit: Operational flexibility and incentives for EVs to support generation and load balancing	Managing and/or incentivizing EV charging loads can reduce peak loads by shifting charging to low net load periods, essentially flattening the load curve. This could reduce peak loads, reduce renewable curtailment, benefit the customer by paying less for energy through rate structures that are designed to incentivize charging during times of abundant renewable energy.
DER owner benefit: Financial benefits	EV owners can receive financial benefits by responding to financial benefits provided by Tariffs, contracts, and demand response pricing. These responses could range from limiting charging during certain periods or times of the day, to limiting the rate of charging, to discharging. Aggregations or fleets of EVs could benefit from providing more coordinated services during emergency conditions.

Business Case E Justifications and Benefits	Description of Specific Justifications and Benefits
DER owner/operator benefit: Ancillary services market for offering grid services to the Transmission System Operator (TSO) and/or DSO	Aggregations or fleets of EVs, if able to meet the more demanding requirements of ancillary services, could bid grid services to transmission or distribution, potentially in combination with other DER, for financial benefits. (Note from CAISO: While technically this is possible, the economics of this are still elusive when you take into account the costs and risks of wholesale market participation. There are state incentives like NEM which are easier and more cost effective. Regulatory hurdles still exist for load participation outside of Demand Response which does not qualify for frequency regulation participation. Frequency support could however be managed autonomously through the EVSE, but no program/policy exists for this to my knowledge.)
DER owner/operator benefit: DER management efficiency and/or effectiveness benefit.	For vehicle-to-home (V2H) applications, EVs could provide electric storage support to homes or buildings during power outages. For example, a single stationary battery system provides about 13 kWh of power, while a typical EV battery contains 65 kWh of power. In some scenarios where prolonged outages are increasingly common due to climate change, EVs could "carry" power by driving from energized grid locations to homes and buildings in outage areas.
Ratepayer benefit: Provision of grid services even to ratepayers who do not own these DER implementations	In general, ratepayers will benefit from more renewable energy DER installed and EVs driven, so long as the management of these systems can be handled. In particular, community microgrids could include storage capabilities from EVs that would provide more resilient and efficient power, even to ratepayers who do not own EVs.
Societal benefit: Equalizing the cost of energy across all types and locations of customers	Although the transition will be complex and challenging to go from "traditional" DSO grid structures to "future" grid structures with significant amounts of DER generation, DER storage including EVs, and managed loads, ultimately such a transition will be very beneficial to society as fuel costs decrease and energy efficiency improves. EVs can play an important role in this process, due to their flexibility and, in aggregate, significant capabilities to provide grid services.
Societal benefit: Reduce use of fossil fuels	Increasing the use of EVs while managing their services to the grid will reduce the use of fossil fuels and help California meet the goals of SB 100[28].

8.4 Business Case E: Regulatory Proceedings

The regulatory roadmap for Business Case E involves the High DER proceeding and the Electrification proceeding. Some of the DSOs have V2G projects, while UL is developing UL 1741 SC for V2G AC certification requirements, based on SAE J3072 and input from SCE based on their EPIC GT 18-0015 V2G project.

D.22-11-040[29] directed ED staff to manage a study to examine the value to the grid of Automated Load Management (ALM) / Energy Management System (EMS). ALM allows the EVSE installers to limit the timing, duration, and maximum power level available at each EVSE. This allows a developer the opportunity to install more EVSE than the site has capacity for if no smart charging options are used. A developer can program their ALM to respond to circuit conditions. As ALM is installed on a site-by-site basis, contractual obligations can be considered when a developer programs the parameters of charging management. The results of this study should be available late 2023 - early 2024.

[28] *California Senate Bill 100, filed 2018, https://www.energy.ca.gov/sb100*

[29] *Decision D.22-11-040, 2022, Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification. Rulemaking 18-12-006, Decision on Transportation Electrification Policy and Investment*

D.14-05-033[30] adopted metering rules for storage to "ensure that NEM credits can only be generated by eligible renewable electric generation". The implication is to ensure that only "green electrons" (created by renewable energy sources) can be exported, and not "brown electrons" (created by non-renewable energy sources). Clarity was needed about whether storage was an "addition or enhancement" to a NEM eligible renewable generation facility, as defined in Public Resource Code Sec. 25741 (a)(1) and referenced by PU Code Sec. 2827 (b)(11).

Additional clarity is now needed to determine how the requirements of D.14-045-033 would apply to V2G systems since it is not possible to determine if the energy stored in a V2G came from a renewable source or not. Similarly, it is not possible to use net generation output meters (NGOM) for mobile assets since they could have been charged somewhere else and it would not be possible to determine whether that source was renewable or not.

D.14-05-033 will need to be reviewed for applicability to V2G projects and amended. If D14-05-033 is determined not to apply to V2G pilots due to use of dynamic Tariffs, then additional clarity will be needed to provide clear and consistent requirements for both mobile and stationary storage systems using dynamic Tariffs such as BEV2 and the Net Billing Tariff.

Table 14 identifies some of the regulatory proceedings applicable to EV interconnection issues.

Table 14: Regulatory proceedings impacted by Business Case E

Regulatory Impacts	**Power Export and Import Limits as a Distribution Service**
Regulatory Processes	**Description**
Update Rule 21	It is possible that Rule 21 Tariff might require some EV-specific updates for V2G requirements. It is unclear if storage-specific updates for charging EVs might be added to Rule 21 Tariff (given on-going discussions in the revision to IEEE Std 1547-2018) or whether that would be the province of Rules 2, 15, or 16.
Update another Rule e.g. Rule 2	New types of loads, such as charging of EVs, can impact the grid and cause thermal overloads. Therefore, adding "load import limits" may need to be addressed by the CPUC. The relevant Rules are Rule 2, Rule 15, and Rule 16. D.22-11-040 addresses the ability to limit the timing, duration, and maximum power level of EVSEs. D.14-05-033 adopted metering rules for storage to "ensure that NEM credits can only be generated by eligible renewable electric generation".
Contractual between DSO and specific DER owner/ operators	Schedules or commands could be permitted by the appropriate CPUC Rules or by individual contracts for load limiting.
Ancillary services bidding or market issue needing rulings	EVs in aggregate or in fleets could provide ancillary services if permitted by regulations or through energy markets

[30] *Decision D.14-05-033, 2014, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self Generation Incentive Program and Other Distributed Generation Issues. Rulemaking 12-11-005, Decision Regarding Net Energy Metering Interconnection Eligibility for Storage Devices Paired with Net Energy Metering Generation Facilities*

8.5 Business Case E: Identification of High Priority Use Cases Supporting Business Case E

8.5.1 Overview of Electric Vehicle High Priority Use Cases

Six Use Cases were identified as high priority for potentially being able to support the requirements for Business Case E, based on expanding the use of existing inverter functionality as defined in Rule 21 Tariff.

These Use Cases focus on managing active power, primarily when charging, to provide distribution grid services. One Use Case, Watt-Var function, involves reactive power for active power support. Other Use Cases were deemed important, but not high priority, while others were assessed as being low priority.

The six high priority Use Cases are:

- Use Case #E1: EV Peak Power Limiting (Demand Response or Limiting Import)
- Use Case #E4: Volt-Watt Response by EVs
- Use Case #E8: Coordinated Charge/ Discharge of EVs to Ensure Desired State of Charge is Reached at the Requested Time
- Use Case #E9: V2G EV as DER (Meeting Rule 21 Tariff requirements)
- Use Case #E12: Watt-Var function
- Use Case #E15: Limit Active Power Export function

The assessments of these Use Cases determined the possible benefits for different stakeholders, the challenges, and the implications for DSO ADMS/DERMS and communications, as well as the challenges and implications for DER owner/operators and Aggregators.

8.5.2 Use Case E1: EV Peak Power Limiting (Demand Response and Import Limiting)

For the Peak Power Limiting of Electric Vehicles (Planned or Emergency Load Reduction), the DSO determines that thermal overload constraint of specific circuits is required for the near future. Since these circuits contain charging stations for EVs, the DSO issues a Load Import Limit schedule or command (see Use Case 4), containing the limit of active power import permitted during the constrained times. The charging station management system (CSMS) then determines if the EVs charging during that time would exceed the import limit. If so, it can request any non-EV DER to increase generation to cover the EV loads. If such a DER does not exist or cannot make up the difference, the CSMS reviews any contractual obligations for the EVs (e.g., emergency vehicles could continue rapid charging) or financial constraints (e.g., an EV owner requests rapid charging), and then determines which other EVs would have their rate of charging slowed down.

8.5.3 Use Case E4: Volt-Watt Response by EVs

Use Case E4: Volt-Watt Response by EVs: The CSMS would monitor the voltage at the PCC. If the voltage at the PCC is below the voltage limits, the CSMS would allocate the proportion of the Volt-Watt response to each EV (and its EVSE) currently charging, and the EVSEs would decrease the charging rate of the connected EVs according to this Volt-Watt proportion., namely, as voltage drops, the power draw would also drop to produce a steady state or constant current control mechanism. This is what is recommended through the NERC EV charging guidelines.

Although this Use Case is only for decreasing active power of those EVs charging, the same criteria could be used for any V2G EVs that are able to increase active power by discharging.

8.5.4 Use Case E8: Coordinated Charge/ Discharge of EVs

Use Case E8: Coordinated Charge/ Discharge of EVs to Ensure Desired State of Charge is Reached at the Requested Time: The CSMS receives information from the EV's owner that informs the CSMS the time by when the EV is required to reach a specified state of charge. The CSMS then takes this information into account as it determines when and how fast to charge the EV. Considerations include not only the current, on-peak/off-peak, and forecast price of energy, but also any demand charges, load import limits, use of the EV to provide other ancillary services, etc.

8.5.5 Use Case E9: V2G EV as DER

Use Case E9: Permission for a V2G-capable EV to Discharge: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function (permission to "Enter Service", meaning to start generating), SAE J3072 describes the interoperability requirements for EVs and EVSEs for permission to discharge. The functions required include the IEEE Std 1547 Permission to Enter Service function and the Set Active Power function. Many other functions, including Fast Frequency Response and Artificial Inertia, could also be provided by V2G. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC.

8.5.6 Use Case E12: Watt-Var function

Use Case E12: Watt-Var function: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function, SAE J3072 describes the interoperability requirements for EVs and EVSEs to establish the curves and other parameters for the Watt-Var function. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC.

8.5.7 Use Case E15: Limit Active Power Export function

Use Case E15: Limit Active Power Export function: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function, SAE J3072 describes the interoperability requirements for EVs and EVSEs to establish the parameters for the Limit Active Power function. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC.

8.5.8 SIOWG Participant Consensus, Non-Consensus, and/or Qualifications with Business Case E

8.5.8.1 SCE Consensus, Non-Consensus, and/or Qualifications for Business Case E

SCE supports this concept; However, SCE does not view as this Business Case E as necessary given that all the functionalities as outlined in Business Case E can be provided using Business cases A, B. and C. Therefore, SCE does not support adding this Business Case.

8.5.8.2 PG&E Consensus, Non-Consensus, and/or Qualifications for Business Case E

PG&E views the EV use case as a subset of the existing Business Cases (A, B, C) because the interconnection location (EVSE / ISE) would be studied via the Planning process and therefore it should not require an additional separate business case because the functionalities are similar. If in the future V2G AC does not require some type of EVSE / ISE, this may require additional consideration for determining interconnection rules. However overall, PG&E supports the concept of using EVs/EVSEs as an asset for flexible connections and for distribution grid services within the existing framework of Business Cases A, B, and C.

8.5.8.3 SDG&E Consensus, Non-Consensus, and/or Qualifications for Business Case E

SDG&E is adding the distribution capacity necessary to accommodate electric vehicle charging loads. Accordingly, SDG&E does not see the need for the CPUC to address "adding 'load import limits'" as referenced in Table 11, except, perhaps, in the context of a customer's voluntary consent to accept such limits in exchange for some benefit (e.g., if accepting such a limit allows the charging load to be connected to the grid earlier than otherwise would be possible).

8.5.8.4 CAISO Consensus, Non-Consensus, and/or Qualifications for Business Case E

The ISO Supports Business Case E given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSE's) along with any export capacity providing grid services to the ISO. In addition, the ISO believes that certain EV value use cases can be achieved through inverter control to achieve 'grid friendly' charging and incentivizing EV load management through grid informed rates.

8.5.8.5 Enphase Consensus, Non-Consensus, and/or Qualifications for Business Case A

In general, it looks very good, and Enphase supports the Business Cases.

9 Business Case F: Operational Flexibility in Community Microgrids

9.1 Business Case F: Description

Business Case F addresses community microgrid management both when grid-connected and when islanded. Community microgrids consist of customers electrically connected using DSO wires, transformers, protection equipment, DER systems, and other DSO assets. They also have at least one microgrid management system that can control the DER systems and loads within the microgrid. They are distinct from other types of microgrids in that they utilize utility distribution facilities.

When grid connected, the community microgrid is identical to any other virtual power plant and would be expected to support the operational flexibility described in Business Cases A, B, and C.

When islanded, the DSO will continue to be responsible for the assets it owns within the microgrid[31], in collaboration with the microgrid management system that is responsible for balancing the generation and load, and for maintaining frequency and voltage within required limits[32]. This means that the DSO solely determines if

[31] *California Code, Public Utilities Code - PUC § 399.2, an electrical corporation shall maintain operational control of the distribution infrastructure that is owned by the electrical corporation.*

[32] *PG&E AL 7042-E microgrid operating agreement. Protest period closed. AL currently suspended. https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7042-E.pdf, PG&E AL 7042-E-A supplement specific to the microgrid incentive program. Protest period on just supplemental information ends 1/15 (which rolls to 1/16 because of holiday) https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7042-E-A.pdf,*

an island will be authorized to form, and that the DSO solely determines if the island is stable. It does not mean that the DSO controls resources owned by others within the community microgrid footprint during island mode. For example, a third party owned battery would be discharged only by the resource owner and at the rate the resource owner chooses. If that third party owned battery was the grid forming resource, then the resource owner could choose to not form the island even if the DSO were to authorize its formation.

Community microgrids will contain both DER generation sources and loads. Since the generation sources and circuit constraints will be different when the microgrid is islanded, management of generation and loads will also parameters and control schemes to be different. For instance, the firm export and/or firm import limits as well as the non-firm export and/or import capacities may be different when the microgrid is islanded. Schedules of these values could be very different, and commands could be expected to manage generation and controllable loads in real-time. Therefore, the agreements between the DSO and the microgrid parties should include what types of changes would be expected.

9.2 Business Case F: Purposes of Community Microgrids

The purpose of Business Case F is to ensure that DSO assets are managed appropriately while still permitting the community microgrid to utilize the capabilities of microgrids, both grid-connected and islanded, to provide grid services such as described in Business Case B and Business Case C.

One obvious community microgrid service for its customers is the ability to island, when it would provide power whenever the distribution grid is experiencing an outage or is expecting a planned outage or is not providing the desired service level (e.g., brownouts, voltage fluctuations).

Microgrid services for DSOs could include virtual power plant (VPP) grid support functions such as frequency and voltage ride-through, frequency droop, voltage regulation, active power export and import limiting, and other Rule 21 Tariff and IEEE Std 1547-2018 functions. In addition, microgrids could provide the PSPS capability to intentionally island if the utility is concerned about wild fires or storms. Additional microgrid services could include special requests for additional generation export during heat waves or other emergency situations.

Community microgrids might also be able to provide services to CAISO while grid-connected since the microgrid management system has direct control of the microgrid DER and loads.

Microgrid energy services could also include opportunities to minimize energy costs for the microgrid owners (who could include the customers within the microgrid, disadvantaged communities, third-party owners, or hybrid ownership of customers and third-parties). These microgrid services could include “energy arbitrage”: exporting power when the price of generated power is high and importing power from the grid when the price for serving load is low. These prices could be set by tariffs, contracts, energy markets, and/or demand response programs.

Microgrid energy services could also benefit society by using renewable energy sources more effectively and efficiently through technical capabilities and financial incentives to customers.

9.3 Business Case F: Justifications and Benefits of Community Microgrids

Business Case F identifies the benefits and justifications to the different stakeholders. In general, the DSOs benefit from safety, reliability, and efficiency. The community microgrid customers benefit from reliability and

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SCE AL 5119-E microgrid operating agreement. Protest period closed. AL currently suspended. Supplemental specific to the microgrid incentive program is expected. *https://edisonintl.sharepoint.com/teams/Public/TM2/Shared%20Documents/Public/Regulatory/Filings-Advice%20Letters/Pending/Electric/ELECTRIC_5119-E.pdf?CT=1704922962538&OR=ItemsView*

SDG&E AL 4303-E microgrid operating agreement. Protest period closed. AL currently suspended. Supplemental specific to the microgrid incentive program is expected. https://tariff.sdge.com/tm2/pdf/submittals/ELEC_4303-E.pdf potentially reduced energy costs, while the microgrid owners might be able to benefit from revenues due to “energy arbitrage”. Often only by combining these benefits can the expense of installing and operating microgrids be justified.

The microgrids can remain grid-connected most of the time or can be islanded for a variety of reasons. If islanded, the generation must be able to balance the load, so active management of generation, storage, and load is required.

These microgrids can benefit the microgrid customers by providing increased reliability and minimizing outages. However, the microgrid implementation expense often needs additional justification, often by providing revenues to their owners. These benefits and justifications are discussed in Table 5.

Table 15: Justifications and Benefits for Stakeholders for Business Case F

Business Case F Justifications and Benefits	Description of Specific Justifications and Benefits
DSO benefit: Operational safety to minimize personnel harm and equipment damage	Wildfires are sometimes caused by power system equipment, particularly during dry windy conditions. To minimize this danger, the DSO shuts down portions of the grid, causing outages to all customers within those grid areas. However, microgrids can be used to energize some if not all of these customers.
DSO benefit: Operational reliability to minimize power outages	During storms or due to other circumstances, circuits can trip off and cause outages to all customers on those circuits. Microgrids can prevent or minimize these outages by using local generation and storage to meet loads, and/or perform load control actions as well. Most microgrids will need to include energy storage or fossil fuel generators to compensate for renewable energy variations in power and controllability. In the near future, electric vehicles will be capable of providing this energy storage particularly if other sources are not available.
DSO benefit: Operational flexibility to meet reliability and efficiency goals through timely response to situations	For DSOs, microgrids, assuming appropriate contracts and permissions, can be used as dispatchable DERs to meet specific goals such as managing active power and/or voltage on a circuit. Some microgrids, because they might include sophisticated energy management capabilities, could also respond to frequency anomalies by providing fast frequency response and artificial inertia.
DSO benefit: Operational capacity to meet renewable energy goals and DSO savings from deferring construction costs	Microgrids, because they would have to include some level of energy management capabilities, could increase the capacity to interconnect more renewable resources on circuits by responding automatically or through communications to emergency situations.
DER owner benefit: Financial benefits	Microgrid owners could benefit from energy arbitrage – buy power during off-peak and selling power during on-peak.
DER owner/operator benefit: Ancillary services market for offering grid services to the Transmission System Operator (TSO) and/or DSO	Microgrid owner/operators could offer ancillary services to the DSO and/or the TSO for additional revenue, assuming they are still able to meet their customers’ requirements. These ancillary services could include unique capabilities such as black start.
DER owner/operator benefit: DER management efficiency and/or effectiveness benefit.	The microgrid operator could manage the microgrid, whether connected or islanded, to optimize efficiency. This efficiency may be part of energy arbitrage.
Microgrid customer benefit:	The customers within the microgrid could benefit directly from the higher reliability, the energy arbitrage and/or the efficiency provided by the microgrid.

Business Case F Justifications and Benefits	Description of Specific Justifications and Benefits
Ratepayer benefit: Provision of grid services even to ratepayers who do not own these DER implementations	Other ratepayers may benefit from lower Tariffs over time, due to improved efficiency provided by microgrids.
Societal benefit: Equalizing the cost of energy across all types and locations of customers	Societal benefits might arise indirectly through the increased capability of the microgrids to provide services to the DSO, thus making the grid more reliable in general.
Societal benefit: Reduce use of fossil fuels	Microgrids can manage their generation and loads to provide grid services so they could increase the capacity of the grid to support more renewable energy, thus supporting California's SB 100 goals.

9.4 Business Case F: Regulatory Proceedings

The regulatory roadmap for Business Case F involves determining which CPUC proceedings could include the necessary rulings for ensuring the safe and appropriate use of DSO assets when the community microgrid is islanded. When grid-connected, the community microgrid would need to meet any VPP requirements and, if providing services to CAISO, all CAISO requirements. When islanded, community microgrid rules and tariffs are being developed in Track 5 of the CPUC Microgrid Proceeding R.19-09-009, with a proposed decision expected in the summer 2024 and with DSO Advice Letters to follow.

The SIOWG Use Cases are not different for community microgrids per se, so that the SIOWG recommendations related to the other SIOWG Use Cases and Business Cases will be fully applicable to community microgrid operation and DER operation in both islanded (emergency) and ordinary grid connected (blue sky) modes. This includes the types of parameters needed for power import, export, active power setting, reactive power, and voltage, plus any variable limits and emergency operation parameters. However, the actual values of these parameters may be different in islanded mode.

A community microgrid is defined by its use of utility distribution facilities in both ordinary and islanded operation, and the responsibilities and authorities over control and operation of both utility and customer or third party facilities and resources remain with the respective owners and their tariff or contractual agreements.

The Community Microgrid Business Case F includes reliability and resilience services, including DIDF alternatives, and potential additional services between non-DSO resources and customers within the microgrid.

9.5 Business Case F: Identification of High Priority Use Cases

Three (3) Use Cases were identified as high priority for potentially being able to support the requirements for Business Case F, based on expanding the use of existing inverter functionality as defined in Rule 21 Tariff.

The high priority Use Cases are:

- Use Case #F1: Customer services, DSO services, and CAISO services when grid connected (acting as a VPP)
- Use Case #F2: Community microgrid islanding process (ensuring safe and appropriate use of DSO assets and procedures, including mutually agreed modifications to Rule 21 settings)
- Use Case #F3: Community microgrid management when islanded (ensuring safe and appropriate use of DSO assets and procedures)

9.5.1 Use Case #F1: Customer Services, DSO Services, and CAISO Services When Grid-Connected

Acting as a VPP, the community microgrid can provide a key customer service: energy arbitrage. Energy arbitrage uses near-real-time pricing information, including both the cost of energy and any congestion prices, to minimize costs and even optimize revenues. Energy arbitrage involves the shifting of energy production from lower-priced to higher-priced times, and the corresponding shifting of energy use from higher price to lower priced times.

For DSO services, the community microgrid management system determines which DER systems and which loads will participate in meeting the active power export limits at each of its customers' PCCs, taking into account facility generation capabilities and forecasts, facility loads, the charging of energy storage, the charging of electric vehicles, and any other considerations which could affect the export or import of active power at the PCCs.

9.5.2 Use Case #F2: Community Microgrid Islanding Process

Community microgrid management involves a number of processes that involve the use of DSO assets:

- Planned transitioning from grid-connected to islanded mode.
- Unplanned (emergency) transitioning from grid-connected to islanded mode.
- Reconnection from islanded to grid-connected and their integration into the utility grid.

9.5.3 Use Case #F3: Community Microgrid Management When Islanded

This Use Case addresses the planning for and managing of community microgrids with grid forming and grid following DER, as well as controllable load, while ensuring safe and appropriate use of DSO assets to help maintain the frequency and voltage of microgrid equipment. Community microgrid planning and management also addresses Black Start when transitioning from an unenergized state to an energized state.

DSO equipment within the community microgrid would be subject to the smart inverter functions but could be subject to some functions that would be needed for managing storage and controllable loads:

- Charge/Discharge (Set Active Power)
- Coordinated Charge/Discharge (Charge EV only at specific times for specific amount)
- Peak Power Limiting (Limit Load)
- Generation Following
- Load Following
- Automatic Generation Control (AGC) (manage frequency based on Balancing Authority commands)
- Active Power Smoothing
- Artificial Inertia (pretend to have ramping constraints like turbines due to mechanics of physical devices rather than software like inverters in DER)
- Fast Frequency Response (FFR) (increase or decrease power rapidly during a frequency emergency) (TBD)
- Power Factor Correction
- Responses to Pricing Signals

9.5.4 SIOWG Participant Consensus, Non-Consensus, and/or Qualifications with Business Case F

Unfortunately, Business Case F was originally not considered high priority because it appeared out-of-scope (i.e., when a microgrid is connected to the grid, it could be seen as a type of Virtual Power Plant. When islanded, it was seen as not under DSO management.) However, it was eventually determined that if parts of the DSO's equipment (wires, transformers, etc.) were included in the microgrid, the DSO was still responsible for ensuring that this equipment would be utilized correctly and safely. Due to this late decision, no consensus or non-consensus statements were received before this working group report was issued to the service list.

9.5.4.1 SCE Consensus, Non-Consensus, and/or Qualifications for Business Case F

SCE's view is that this business case should be addressed in the CPUC's microgrid proceeding.

10 Business Case G: Operational Flexibility for DER Providing ISO Grid Services

10.1 Description of Business Case G

Business Case G addresses grid services that could be provided by DER to the bulk power system. Although most DER are relatively small (<1 MW), in aggregate they can either negatively impact or positively improve the reliability, performance, and efficiency of the bulk power system. The grid services that could be provided by DER include energy and ancillary services. These services could be mandatory (if so regulated) or contractual or market-driven through price signals or direct market participation, with different jurisdictions determining different requirements for these grid services. In this context, grid services provided by DER can include both generation and load-related services, as well as frequency support, voltage support, and contingency support.

The CAISO recognizes the value of DER integration and has actively worked with stakeholders to create opportunities to provide grid services from DER through load curtailment, load shift, and export of energy. The CAISO also believes that DER can provide value through grid informed retail rates that incentivize consumption that aligns to system grid conditions without participating directly in the CAISO markets.

Note that:

- The CPUC has jurisdiction over the Rule 21 Tariff and the related implementation and use of IEEE 1547 to support Rule 21.
- CAISO has jurisdiction over IEEE 2800 and WDAT.
- The DSOs are responsible for ensuring the technical quality requirements of WDAT are met, even though it is the FERC Tariff.

More detail on the regulatory issues between the CPUC and CAISO are discussed in Section 1.4.

10.2 Purpose to Solve Problems or Provide Opportunities for Different Stakeholders

The purpose of Business Case G is to assess which DER smart inverter capabilities could improve the reliability, performance, and/or efficiency of bulk power system, including minimizing the need for fossil fuel generation or the use of less reliable, or more costly sources of generation. These DER capabilities could include methods for helping frequency control, supporting voltage stability, minimizing peak load demands, smoothing transitions between different power sources, and minimizing energy fluctuations caused by variable and intermittent renewable energy sources or by Tariff -driven or time-driven loads.

Providing DER grid services to the bulk power system has the potential to offer opportunities for stakeholders. Aggregators can request and provision grid services from the DER resources they represent by presenting financial and/or societal incentives (e.g., green power) to their DER customers. Larger facilities, such as industrial plants, shopping centers, office complexes, university campuses, large EV charging stations, and community microgrids could offer grid services to the bulk power operators without the need for aggregation. Realizing these opportunities requires that processes are in place to ensure the reliability of the distribution grid can be operated safely and reliably. In addition, CAISO would need to assess the financial aspects to determine the cost-effectiveness of the services.

10.3 Justifications and Benefits for Stakeholders for Business Case G

Business Case G addresses the justifications and benefits to all stakeholders, ranging from minimizing bulk power disturbances to easing the transition to renewable energy to providing financial incentives.

Electric power systems are changing rapidly due to the introduction of variable and intermittent renewable energy sources, the rapid increase of distributed generation and electric vehicles, the unpredictable impacts of climate change on weather, and the increased reliance of society on uninterrupted electric energy. These changes imply the need to revisit not only the structure and capabilities of the distribution system but also the bulk power system grid services, as the grid is affected by the location and the amount of DER as well as by the difficult-to-predict location of load growth and/or reduction. With the ability of bulk power operators to calculate locational marginal prices (LMP), DER operators could assess these pricing incentives, particularly during critical or emergency conditions, and determine whether and how to provide the needed grid services.

In particular, the U.S. Energy Information Administration forecasts that electricity consumption by the transportation sector alone will increase by more than a factor of 12 between 2021 and 2050 (from 12 billion kWh in 2021 to more than 145 billion kWh in 2050). Considering all forms of electrification across North America, Wood Mackenzie projects that electricity consumption in 2050 – by transportation and building electrification after subtracting projected increases in on-site generation (e.g., rooftop solar PV) – will represent a 66% increase over total electricity consumption in 2022.[33]

Table 16 indicates the justifications and benefits for stakeholders in Business Case G.

Table 16: Justifications and Benefits for Stakeholders in Business Case G

Business Case G Justifications and Benefits	Description of Specific Justifications and Benefits
CAISO, Distribution Operators, Transmission Operators, DER Aggregators, and retail consumers	Distribution operators, transmission operators, DER Aggregators, and retail consumers will benefit from DERs utilizing the features of advanced inverters which will improve grid reliability, voltage and frequency stability, and accurate performance of DER when providing grid services directly in markets or when responding to grid signals or grid informed retail rates.
Transmission Operators benefit: Operational safety to minimize personnel harm and equipment damage	Using DER as well as bulk power generating plants for managing the provision of power to support loads can help minimize possible bulk power grid problems that affect CAISO balancing requirements, such as path congestion, thermal overloads, voltage sags or spikes, or frequency excursions. The bulk power grid disturbances could cause harm to personnel as well as equipment.

[33] *California Mobility Center (CMC), "Electric Vehicle Dynamic Charging Performance Characteristics during Bulk Power System Disturbances", April, 2023,* https://10af82ed-e985-4e24-b989-2d4e8ed60bc1.usrfiles.com/ugd/10af82_bbcd711902dd4efdaf6e8d77cd246163.pdf

Business Case G Justifications and Benefits	Description of Specific Justifications and Benefits
CAISO benefit: Operational reliability to minimize power outages	The increased use of fluctuating renewable energy, the unpredictability of weather events caused by climate change, and the rapid addition of electric vehicle charging at locations without historical records or analysis, could cause bulk power system disturbances and outages. Aggregations of DER and/or the larger DER sites could provide grid services to minimize the likelihood and/or severity of these disturbances and outages, thus improving bulk power reliability.
CAISO benefit: Operational flexibility to meet reliability and efficiency goals through timely response to situations	Timely requests for DER grid services, whether year-ahead, week-ahead, day-ahead, hour-ahead, or immediate, could provide the flexibility needed to help meet reliability and efficiency goals, and could help plan for known contingencies. For instance, virtual power plants, microgrids, large DER facilities, and groups of smaller DER facilities could use information from CAISO on services that could help support reliability and efficiency goals.
DER owner/operator benefit: Financial benefits from providing grid services in the ancillary services market	Aggregators and DER owners could receive financial benefits from providing grid services to CAISO. These services could be part of contracts or could be more market-based. Some grid services, such as operational reserve, could have minimal impact on actual DER operations except during emergencies.
DER owner/operator benefit: DER management efficiency and/or effectiveness benefit.	Aggregators and DER owners could benefit from having more reliable and efficient power from the bulk power system.
Ratepayer benefit: savings from deferring construction costs	Using aggregations of DER to better manage demand could defer construction and related grid management costs, not only at the distribution level, but also at the bulk power level.
Ratepayer benefit: Provision of grid services even to ratepayers who do not own these DER or EVs	Ratepayers could benefit from a more reliable and efficient bulk power system, including fewer and shorter outages. These benefits could become reflected in lower retail transmission and commodity costs.
Societal benefit: Equalizing the cost of energy across all types and locations of customers	Societal benefits could accrue from collections of customers who opt into providing these bulk power grid services with renewable energy due to the reduced cost of electric power.
Societal benefit: Reduce use of fossil fuels	Improving the reliability and performance of the bulk power system will help in reducing the need for fossil fuel generation to offset the variability and unpredictability of renewable energy sources.

10.4 Applicable Regulatory Proceedings or ISO Stakeholder Initiatives for Business Case G

The regulatory roadmap for Business Case G involves CAISO and the bulk power regulators, such as FERC, NERC, WECC, etc. There are some gray areas that may or may not need to be resolved: for instance, can a DER provide both CAISO services based on WDAT requirements and distribution grid services based on using smart inverter functions?

CAISO will continue to evolve opportunities for DER's to participate within markets as well as work closely with State Agencies, DSOs, Aggregators, and Load Serving Entities to provide DER value to the grid and DER owners through non-market mechanisms.

The ISO is complying with FERC orders such as FO 2222 to ensure that DER have an opportunity to participate in wholesale markets when meeting the requirements of distribution DSO Tariff , CPUC and other distribution level local regulatory authorities.

Table 17 identifies some of the regulatory proceedings impacted by Business Case G, with most outside of the distribution domain.

Table 17: Regulatory proceedings impacted by Business Case G

Regulatory Impacts	
Regulatory Processes	**Description**
FERC Order No. 2222	FO2222 removes the barriers preventing distributed energy resources (DERs) from competing on a level playing field in the organized capacity, energy and ancillary services markets run by regional grid operators
CPUC R.21-06-017	Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future
CPUC R.22-07-005	Leverage demand response (also referred to as load or demand flexibility management) as a critical resource in integrated resource planning (IRP) to meet the State's aggressive GHG emissions reduction targets.
CPUC R.19-09-009	Design a framework surrounding the commercialization of microgrids associated with Senate Bill (SB) 1339 (Stern, 2018), as well as to account for the Commission's commitment toward utilizing additional technologies and activities that may be useful for achieving overall resiliency goals.
CPUC R.18-12-006	Development of Rates and Infrastructure for Vehicle Electrification (R.18-12-006, DRIVE Rulemaking) to refocus transportation electrification efforts.
Update CAISO regulations	The CAISO will continue to work with stakeholders and state and federal regulatory agencies to provide opportunities for DER to provide transmission level wholesale grid services into the CAISO markets. The CAISO will work with state agencies to support distribution level policy and technical developments which help qualify DER for wholesale participation. As CAISO, state, and federal policy and rules are developed, the CAISO engage with these stakeholders to demonstrate value, as well as implement and evolve DER grid integration.
Update Rule 21	Can a DER provide both CAISO services based on WDAT requirements and distribution grid services based on using Rule 21 Tariff functions?
Update another Rule e.g. Rule 2	None
Contractual between DSO and specific DER owner/ operators	Yes

10.5 Technical Assessments of the Use Cases to Achieve the Business Case G

10.5.1 Identification of High Priority Use Cases for Supporting Business Case G

11 Use Cases were identified as high priority for potentially being able to support the requirements for Business Case G, based on expanding the use of existing inverter functionality as defined in Rule 21 Tariff.

These Use Cases focus on DER providing not only traditional ancillary services (Reg Up/Reg Down, Operational Reserve), but also some grid services that either help compensate for large amounts of variable renewable energy or that provide new services due to potentially unforeseen increased loads from electric vehicle charging and other shifts from traditional grid-use patterns.

The following Use Cases were rated as high priority to CAISO (**3 bolded items**) or other stakeholders. CAISO has commented further in the detailed descriptions below the list:

- **Use Case G1: Fast Frequency Response (FFR)**
- **Use Case G2: Synthetic or Artificial Inertia Frequency-Active Power**
- Use Case G4: Operating Reserve (Spinning Reserve)
- **Use Case G6: Power Factor Limiting (Correcting)**
- Use Case G16: Default Settings and Actions if Communications are interrupted
- Use Case G17: Unintentional Islanding
- Use Case G18: Black Start
- Use Case G19: Anti-Duck Curve Scheduled Dispatch
- Use Case G20: Anti-Duck Curve Dynamic Dispatch
- Use Case G21: Scheduled Capacity
- Use Case G22: Dynamic Demand Response
- Use Case G23: Dynamic Shift Shimmy

The assessments of these Use Cases by the SIOWG members determined the possible benefits for different stakeholders, the challenges and implications for DSO ADMS/DERMS and communications, and challenges and implications for DER owner/operators and Aggregators.

10.5.1.1 Use Case G1: Fast Frequency Response (FFR)

CAISO rated Fast Frequency Response (FFR) as high priority.

The following definition of Fast Frequency Response (FFR) comes from IEEE 2800-2022: *Active power injected to the grid in response to changes in measured or observed frequency during the arresting phase of a frequency excursion event to improve the frequency nadir or initial rate-of-change of frequency.* Detailed performance requirements are also defined in IEEE 2800-2022.

FFR requires specific settings of the frequency-active power capability to respond to frequency changes very rapidly by increasing or decreasing active power. When the transmission and distribution system frequency is outside of a pre-defined frequency deadband range, DERs inject or absorb active power to help push system frequency back within the frequency deadband. FFR systems respond to changes in frequency autonomously in a timeframe of less than one second. This autonomous DER capability requires specific settings of the Frequency-Watt function (currently only having Rule 21 Tariff settings for the Droop capability) to meet these more extreme responses.

CAISO Note on High Rating: *FFR should not be conflated with governor action when frequency exceeds predefined deadbands (e.g. +/-36 mHz in the WECC). The primary need for FFR is to arrest system frequency (frequency nadir point C) to levels above the first block of off-nominal frequency i.e. 59.5 Hz* *within the WECC. For a low frequency event, FFR occurs within the inertia timeframe (approx. 8-seconds in the WECC. FFR can either be fast load rejection from the system or fast MW injection into the system.*

ISO needs to sustain FR duration to approx. 1 minute response Since DER resources could make up over 30-50% of the supply on weekends, DER resources may need to provide FRR should WECC have an inertia problem. DER would need to perform similar to grid connected resources.

10.5.1.2 Use Case G2: Synthetic or Artificial Inertia Frequency-Active Power

CAISO rated Synthetic Inertia as high priority.

For synthetic or artificial inertia, the DER responds to the rate of change of frequency (ROCOF) by changing its active power production (or consumption) to counteract rapid changes (spikes and sags) in frequency.

In fossil fuel rotating machine generators, the inertia of the mechanical rotation inhibits changes in system frequency since the frequency droop of their governors helps to stabilize frequency on the system. When there are frequency deviations, due to changes in load or generation, these large rotating generators inject or absorb active power, in part drawing on inertia, to provide a corrective force.

Inverters do not intrinsically have inertia – they can change power levels almost instantaneously. Therefore, inverters need to be controlled to provide “artificial” inertia through the use of deadbands, slope settings, and response times for frequency droop.

As the number of rotating machine generators decreases, frequency stabilization must also be provided by these inverter-based resources (IBRs), whether they are single large inverters or aggregations of smaller inverters. DERs compliant to Category III of IEEE Std 1547-2018 are capable of frequency support with response times down to 0.2 seconds. Faster response times can be achieved by programming inverters to react to the Rate of Change of Frequency (ROCOF). A standard does not exist for ROCOF functionality, but inverter design and performance can be validated by distribution operators as part of interconnection agreements.

The difference between FFR and artificial inertia is not precisely defined since they both respond very rapidly to changes in frequency. However, artificial inertia mimics the response of rotating masses (rotating generation sources) while FFR may go beyond what rotating masses may provide to respond to emergency levels of frequency deviations. The following description captures these distinctions: *The term synthetic inertial response must therefore correspond to the controlled response from a generating unit to mimic the exchange of rotational energy from a synchronous machine with the power system. Any other form of fast controlled response can then be termed as fast frequency response. To clarify, synthetic inertial response is a subset of fast frequency response which contains different responses based on frequency and ROCOF*[34].

CAISO Note on High Rating: *Technical studies would have to be done to determine how DER can mimic synthetic inertia for low frequency events. As more synchronous resources are displaced by grid connected IBRs, a low frequency event could result in a high RoCoF causing the frequency nadir to drop below 59.5 Hz. Currently, on light load days, DER supplies about 30% of load and that could increase to about 50% or more by 2030. This may create the need for DER to provide some level of synthetic inertia. Since PV cannot provide synthetic inertia when operating at maximum irradiance levels, headroom would have to be made available on PV resources to mimic*

[34] [https://ietresearch.onlinelibrary.wiley.com/doi/10.1049/iet-rpg.2017.0370]

system inertia. Loads and or storage devices would also be able to mimic inertia prior the reaching the frequency nadir.

10.5.1.3 Use Case G4: Operating Reserve (Spinning Reserve) (Tertiary Frequency Control)

CAISO rated Operating Reserve as medium priority.

The DER provides active power reserve to the grid within a short time (potentially seconds but often up to 10 minutes) from when requested. This grid support function is currently an ancillary service which can be provided by bulk power generators. Aggregations of DER could provide this ancillary service if capable, if there are no serious impacts on the distribution system, and if the service could reliably be provided. Although generally considered as providing additional generation, operational reserve could include controllable and reliable reductions in load.

DER participating in the CAISO Market for Spin - Non/Spin must meet same visibility/control/performance requirements as non-DER connected devices. Flow from Distribution to Transmission will tell the CAISO what operating reserves we need. DERs are capable of providing Operating Reserve and further analysis needs to be done to determine the level of participation.

350BA Note on High Rating: *Technology should/could become available in the near term.*

10.5.1.4 Use Case G6: Power Factor Limiting (Correcting)

CAISO rated Power Factor Correcting as medium-to-high priority.

The DER supplies or absorbs Reactive power to hold the power factor at the RPA within the PF limit.

CAISO Note on Medium-to-High Rating: *Reliability Justification. Close coordination between grid and DER resources providing voltage control must be maintained. Today the grid resources are operated to support scheduled voltages while DER resources are operated to maintain a constant power factor. Typically, large t-connected generating resources provided much of the voltage support on the grid and the DER operated at a constant power factor. Now, with a high amount of supply located on the distribution, the industry needs to rethink operating DERs in a constant power factor mode and instead operate in a manner to support schedule voltages and work in unison with grid voltage control devices.*

10.5.1.5 Use Case G16: Default Settings and Actions if Communications are Interrupted

CAISO rated Loss of Communications as low priority. ISO Direct Telemetry BPM Specifies procedure for reporting outage of telemetry (real time device). Participation in Ancillary Services ends and will begin again once the Telemetry has been restored and tested with the ISO.

Neither Rule 21 Tariff nor IEEE Std 1547 define what should be done if communications are lost. However, default settings and actions are critical if the DER responses to loss of communications can be predicted. Such defaults could include steps that could vary depending on how long the communications have been interrupted and what functions or settings are active. For instance, some functions such as Reg Up/ Reg Down require 4-second timeframes, while others may be managed by a schedule. Some functions or grid services could be automated but with control command overrides, such as charging of electric vehicles. Others could be price-driven and would not affect the grid, while others might be fine for an hour, but would need some action if the communications interruptions was longer than that.

Some of the actions that could be taken on communication interruptions could be:

- Continue doing those actions or functions which were already being executed.
- Go to some default state, such as idle or minimum level.

- Shut down.
- Disconnect from the area EPS.
- Take more nuanced approaches, such as disable some functions, enable others, change settings to a default, etc.

350BA Note on High Rating: *Technology already available in the near term.*

10.5.1.6 Use Case G17: Unintentional Islanding vs Pre-Planned Islanding

CAISO rated Unintentional Islanding as medium priority.

Unintentional islanding is defined as unplanned islanding (abnormal separation from the grid during emergencies) and is subject to anti-islanding practices to avoid having a portion of the grid islanded without prior planning for its control and management. However, pre-planned islands (often termed microgrids) can disconnect from the Area EPS due to grid disturbances that cause the microgrid to trip off the grid. If the pre-planning is adequate, the microgrid can continue to operate in islanded mode.

350BA Note on High Rating: *Technology already available in the near term.*

CAISO Note on Medium Rating: *Reliability Justification. Distribution interconnection requirements need to be revisited to avoid unnecessary tripping due to grid faults. Distribution Interconnection rules should be updated to set standards (Rule 21/IEEE1547)*

10.5.1.7 Use Case G18: Black Start

CAISO rated Operating Reserve as low-to-medium priority.

Black start is the ability to use an islanded microgrid with its own power and to add groups of external loads and other generation over time to eventually connect to (or even become) the Area EPS. Microgrids are expected to become more prevalent as backup generators, energy storage systems, and even electric vehicles are installed to provide power to local sites for reliability and energy management purposes. These microgrids could form the sources for black start capabilities after widespread bulk power outages.

350BA Note on High Rating: *Technology should/could become available in the near term.*

CAISO Note on Low-to-Medium Rating: *Studies much be done to understand how inverter-based DER could provide this service. Not sure how inverter functions would support this. The scale of energy needed to black start the grid is best served by large resources. Smaller DER resources may be better used to black start a microgrid. Given challenges already being seen with grid-scale batteries providing black start, the feasibility of DERs providing black start is not clear at this time.*

10.5.1.8 Use Case G19: Anti-Duck Curve Scheduled Dispatch

CAISO rated Anti-Duck Curve Scheduled Dispatch as medium priority.

The "Duck Curve" is the shape of generation when solar power provides a large portion of the power during the day but fades off rapidly in the evening even as loads increase, requiring other sources of generation to provide the energy. Often these other sources are not renewable energy sources and require fossil fuel generators to start up just for this transition into the evening time.

The "Anti-Duck Curve" is shape of generation when actions occur to reshape the load through scheduled day-ahead capacity services by raising the mid-day energy demand and decreasing the evening peak by flattening the load shape[35].

[35] *See https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.*

Different steps could be taken to flatten the load shape. These could include:

- Demand response (DR) incentives for customers to reduce their loads at appropriate times. DR can reduce loads, but often require make-up time later on, either for the loads themselves or for the DER storage systems which provided for the loads during the peak times. Since DR program incentives may vary significantly over time and for different locations, only sophisticated energy management systems can really take advantage of these incentives.
- Tariffs with on-peak times during the afternoon/evening transition into night can provide incentives for DER sites to use energy storage for loads during the on-peak times. Time-of-Use Tariffs are more predictable and therefore easier for DER scheduling, but may not respond to events with the same level of granularity as DR.
- The use of wholesale market Locational Marginal Pricing (LMP) could provide incentives not only for times but also for locations where managing loads (and DER) could be most beneficial. LMP incentives could help the distribution system to minimize the impact of local “Duck Curve” situations.

350BA Note on High Rating: *Technology should/could become available in the near term.*

CAISO Note on Medium Rating: *The distribution system also faces the 'Duck Curve' issue based on local generation of PV offsetting loads. The ISO market produces LMPs to signal oversupply or tight supply conditions. Other methods could be deployed such as time of use rates and 'grid informed' rates to incentivize consumption patterns. Regulatory challenges still exist to provide wholesale access to BTM loads to take advantage of wholesale market LMP.*

G19, G20, G21, G22, and G23 need to be coordinated with time of use rates and grid needs. PDR/RDRR and State/Utility emergency retail programs currently exist and are the only approved means to shape and shift retail load. Retail loads are under state jurisdiction. The state would need to forge new rules and processes to allow retail load to be 'managed' at a wholesale level.

Given the complexity of doing this, the CAISO has been supportive of efforts at the CPUC and CEC to support the development of grid Informed retail rates which would provide an alternative pathway to obtain value from DER. From the LBNL Phase 2 Report: The retail price framework for organizing shift could accomplish the same fundamental dynamics as wholesale market integration but with much more transparent and simple “dispatch” – simply connecting consumption of electricity by particular loads to the forecasted locational marginal price. Automated retail price response would avoid some transactions costs related to scheduling coordinators, eliminate issues related to estimating counterfactual baselines, and eliminate constraints introduced by ISO market dispatch integration

Note*: Might the use of LMP congestion pricing act as a stand-in for the need for Limited Generation Profiles (LGP) on critical circuits? More precisely, how closely are LMP calculations matched to distribution thermal limits, whether or not the problem is generation export or load import? Obviously CAISO looks only at Generation PNodes, Scheduling Points, and Aggregated Pricing Nodes on an hourly basis, as required by the CAISO Tariff , but are these at all aligned with ICA calculations? Could they be aligned in the future? See LMP from the heat wave on 9/6/2022 in* Figure 29*.*

Pushing LMP down into the distribution system -- which is theoretically possible -- raises many complicated technical, regulatory and market issues.

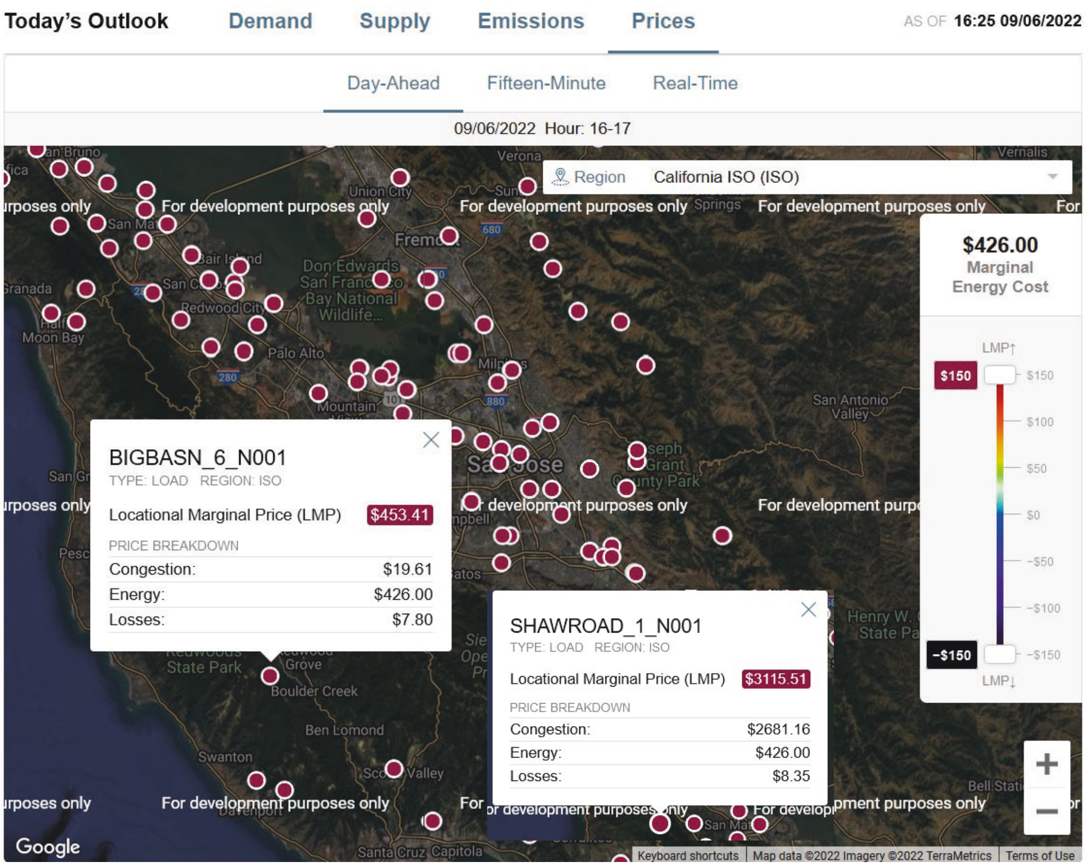

Figure 29: Locational Marginal Prices for Energy and Congestion

10.5.1.9 Use Case G20: Anti-Duck Curve Dynamic Dispatch

CAISO rated Anti-Duck Curve Dynamic Dispatch as medium priority (see comment on G19).

The dynamic reshaping of load based on real-time grid need for daytime excess energy and evening peak demand needs. See https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.

350BA Note on High Rating: *Technology should/could become available in the near term.*

CAISO Note on Medium Rating*: Development of DR capabilities to shift and shape load exist today. CPUC has a significant role in DR administration and ISO can continue to work with the CPUC to evolve these capabilities through TOU rates, DR, Storage. PV is likely operating at Pmax only allowing for downward movement.*

10.5.1.10 Use Case G21: Scheduled Capacity

CAISO rated Scheduled Capacity as medium priority (see comment on G19).

The reshaping of peak load through scheduled day ahead capacity service. https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.

350BA Note on High Rating: *Technology should/could become available in the near term.*

10.5.1.11 Use Case G22: Dynamic Demand Response

CAISO rated Anti-Duck Curve Dynamic Dispatch as medium priority (see comment on G19).

The dynamic reshaping of load based on real-time grid need for evening peak demand needs. See https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.

350BA Note on High Rating: *Technology should/could become available in the near term.*

10.5.1.12 Use Case G23: Dynamic Shift Shimmy

CAISO rated Anti-Duck Curve Dynamic Dispatch as medium priority (see comment on G19).

The dynamic reshaping of load based on real-time grid need for daytime excess energy and afternoon/evening ramp. See https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.

350BA Note on High Rating: *Technology should/could become available in the near term.*

10.5.2 Entities and/or Systems Involved

In the use cases identified as high priority for supporting Business Case G, the following entities or systems are involved:

- CAISO, whose Tariff sets the participation requirements for DER which are capable of providing transmission-level services.
- Scheduling Coordinators who represent the resources participating in the CAISO wholesale market.
- DSO who performs interconnection and reliability studies to define the agreement under which DER can provide energy and capacity to the transmission grid
- CPUC or other Local Regulatory Authorities which develop the policy and requirements under which DER are allowed to utilize distribution load and generation within CAISO markets
- FERC who approves Distribution interconnection agreements d(WDAT) and frameworks allowing DER to provide wholesale market services
- Load Serving Entities and Community Choice Aggregators who fulfill load forecasting and load serving requirements and processes to meet customer electric demand
- Aggregators and DER providers who must work with the DSOs to ensure participation in wholesale markets is reliable and feasible
- Distribution system operators (DSO) who determines what DER constraints and/or support is needed in real time for ensuring the distribution grid can handle the impacts of DER providing transmission services.
- DSO ADMS/DERMS which includes capabilities for monitoring the grid, as well as applications used to study, schedule, and issue control commands to facilities that could include charging or discharging of EVs. This monitoring and control may be directly with the facility’s Power Control System (PCS) or may be indirectly through an Aggregator.
- DER owner and/or operator (e.g. Aggregator, customer) who may permit or reject or modify the requests or commands from the DSO.
- Aggregator Gateway and Aggregator ADERMS which includes capabilities for monitoring EVs, as well as applications used to study, schedule, and issue control commands to facility PCS.
- DER Gateway and Plant Control System which receives and allocates commands from Aggregators and/or DSOs to EVs.
- Revenue-grade meters and/or measurement equipment at the Point of Common Coupling (PCC).

- Microgrid and resource aggregation control systems which can translate ISO and DSO commands from an aggregated command or dispatch to individual resources within the aggregation or microgrid and respond as a single virtual resource back to the grid for performance visibility and settlement

Figure 30 illustrates the interactions between the entities and systems for Business Case G. CAISO EMS interacts with the DSO utility {*yellow*} to determine whether a DER that wishes to provide grid services to CAISO would have a significant impact on the distribution grid. Participation in ISO markets requires bidding through a scheduling coordinator. These bids are awarded and optimized to meet bulk system needs. CAISO's EMS controls the resources providing frequency regulation while the CAISO market dispatches awards to the resources in real time.

The DSO EMS and ADMS/DERMS contain applications for studying and managing DER, including EVs, and may include the ability to interact with the energy market. The DSO interacts with Aggregators {*red*} and Facilities {*blue*} (including Plant Control Systems) through their gateways. The Aggregators interact either directly with individual DER systems {*green*} or indirectly via Facility DER energy management system. DER owner/operators may interact directly with the DER systems for managing charging/ discharging or may interact via the Facility systems. For EVs, interactions may be via OEM or Aggregator systems.

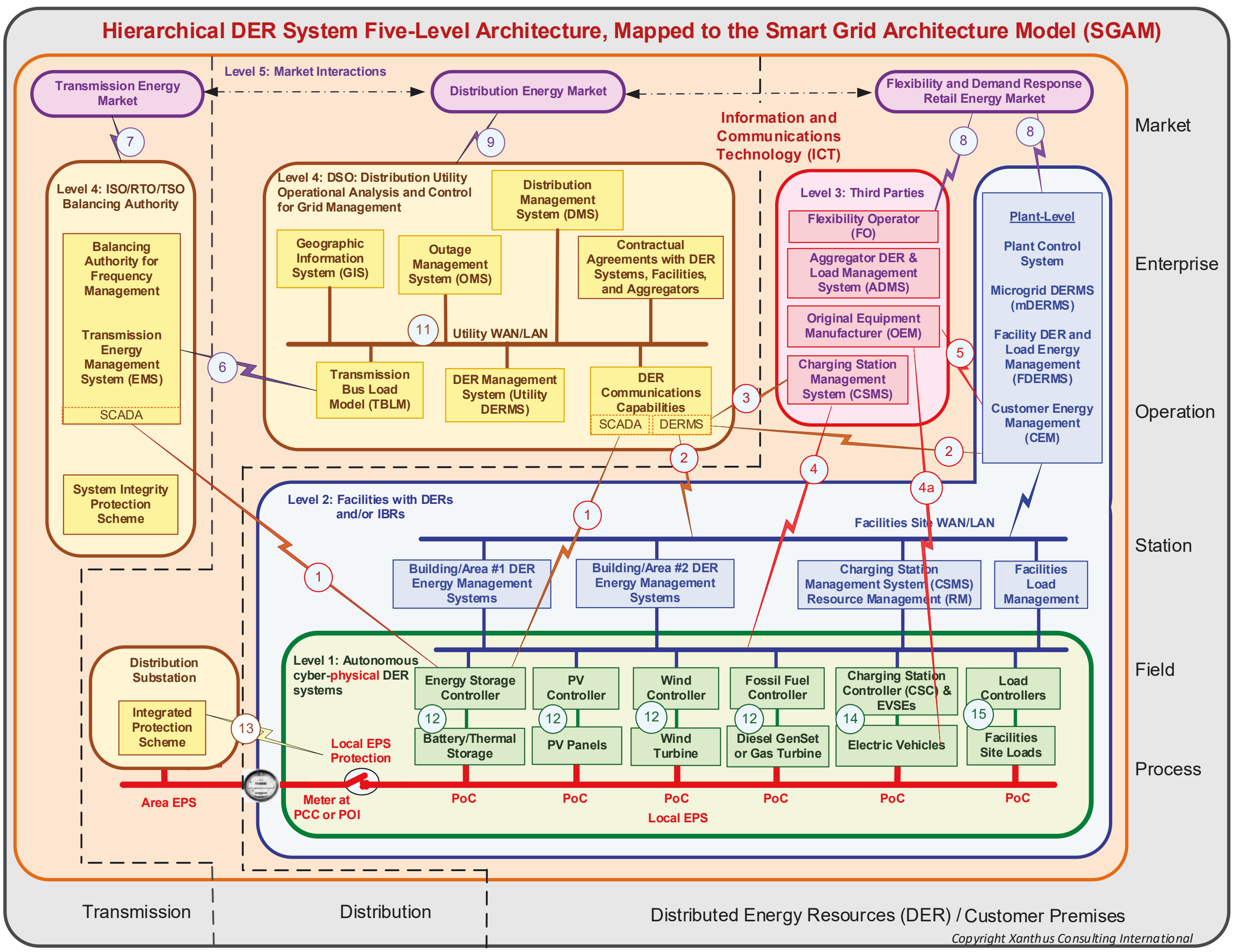

Figure 30: Business Case G: Architecture of Entities, Systems, and Communications

10.5.3 DER Functions in Rule 21

Different Rule 21 Tariff functions could be used, while extensions to some of these functions could be warranted. For instance:

- The frequency-active power function would require different settings for FFR.
- Response to ROCOF would require a new function. This may be added to the revision of IEEE Std 1547.
- Establishing the actual generation or charging settings or commands would require variations to the existing Rule 21 Tariff functions, since managing storage or power control systems was envisioned initially.
- Management of community microgrids which unintentionally or intentionally island is not covered in Rule 21 Tariff (an unintentional island should not be allowed to persist if protection systems are functioning correctly).

10.5.4 Information Types of Exchanges

The types of information exchanged between CAISO and aggregators or DER for the different Use Cases in Business Case G would need to be evaluated. The type and timeliness of this information would depend on the Use Case, including:

- Pricing information for time and location, whether LMP or DR or other type of incentive
- Settings for autonomous functions
- Schedules for time-driven functions
- Commands for event-driven functions
- Bids for providing energy and specific ancillary services
- Resource-specific information (*e.g.,* capacity, ramp rates, operating constraints)
- Monitoring via telemetry or metering for verification of compliance to functions

10.5.5 Communication Protocol Issues

CAISO uses the DNP3 communication protocol between the SCADA system and the RIGS located at remote sites. IEEE Std 1547 includes DNP3 (IEEE 1815) as one of the 3 protocols, and IEEE 1815.2 is currently being developed as the DER profile for interoperable DNP3 communications (balloting in Q1 2024). Depending on the Use Case, it is likely that DNP3 and possibly the DNP3 profile for DER (IEEE 1815.2) will be the communications protocol of choice. Other communication protocols include IEC 61850 and IEEE 2030.5.

10.5.6 CAISO Capabilities/Applications

CAISO has extensive capabilities and applications for balancing the electric grid and handling ancillary services. Additional rules and requirements will be needed to incorporate DER and groups of DER to provide some of those services. Additional information can be provided by CAISO.

- Resources participating in ISO Markets are represented by the services of a Scheduling Coordinator
- Scheduling Coordinators, aggregators, and resource owners have secure access to several CAISO applications and systems which are required for them to participate in the wholesale markets

- These applications include market portals, automatic dispatch, EMS Control, Settlements, and outage management. Detailed information can be found within the CAISO Business Practice Manuals (BPMs)

10.5.7 DSO ADMS/DERMS Capabilities/ Applications

The DSO ADMS/DERMS will need to include certain types of analysis capabilities to support the Business Case G requirements. These could include the following:

- Assessment of potential impacts on the distribution grid if a single DER facility or an aggregation of DER facilities provides grid services to CAISO.
- Assessment of potential impacts on other DER facilities and customers, such as potentially requiring changes to their active power export or import limits, if DER facilities are providing grid services to CAISO.
- Assessment of what actions to take if such impacts actually occur, including scheduling or commanding DER facilities to modify their export and/or import limits, or provide voltage support.

10.5.8 Aggregator ADERMS and/or Facility FDERMS Capabilities/ Applications

The Aggregator ADERMS and/or the Facility FDERMS could need to include additional capabilities to support the Business Case G requirements. These capabilities could include:

- Monitoring and control capability of EV charging and discharging.
- Monitoring of the net active and reactive power of DER and load at the PCC of facilities with large amounts of EVs (e.g., charging stations, fleets, office complexes, etc.)
- Monitoring of voltage and potentially frequency at the PCC if distribution services could involve voltage or frequency functions.
- Providing near-real-time data as required by the DSO to support the distribution services.
- Providing forecasted and near real time data of DER performance and impact on load to CAISO.

10.5.9 Challenges and Implementation Steps for Use Cases

There are many challenges that would need to be addressed before some of the Use Cases could be Implemented. For example:

- DER facilities have the right to participate in the ISO markets today under demand response and the Distribution Energy Resource Provider (DERP) and FERC 2222 frameworks, but this right has not removed challenges on the distribution system or address overall reliability concerns of having DER provide services outside of load curtailment or “Demand Response”.
- The economics or business case for DER is not clear. Not all use cases are appropriate for wholesale participation due to costs and risks.
- DER have other opportunities to derive value through retail mechanisms such as NEM or participating in emergency demand response programs.
- The highest value of DER may be derived at the point of interconnection. Customer level DER can provide the highest value to the consumer by managing loads that take advantage of dynamic retail rates, can avoid DSO demand charges, and can be tailored to customer need as opposed to grid need.

10.5.10 SIOWG Participant Qualifications and/or Non-consensus with Business Case G

10.5.10.1 SCE Consensus, Non-Consensus, and/or Qualifications for Business Case G

SCE supports this concept; However, SCE does not view as this working group being the correct venue to address ISO Grid Services. These use cases and services should be led by ISO as part of ISO grid service development process.

10.5.10.2 PG&E Consensus, Non-Consensus, and/or Qualifications for Business Case G

PG&E supports this concept, in particular, the management of multiple use applications where assets may be participating in both ISO and DSO related services and flexible connections. However, other than the coordination between the ISO and DSO much of this seems unrelated to DSO activities and this should be deferred to the ISO and ISO related venues for addressing many of the topics presented in this chapter.

10.5.10.3 SDG&E Consensus, Non-Consensus, and/or Qualifications for Business Case G

SDG&E agrees with SCE but notes that there needs to be clear processes for managing the interfaces between the transmission and distribution systems when distribution-connected DERs are participating in CAISO markets. This is particularly important during abnormal conditions in the distribution system. The CAISO and other stakeholders have considered these interface issues at length in an earlier working group.

10.5.10.4 CAISO Consensus, Non-Consensus, and/or Qualifications for Business Case G

The ISO is in general support of continued collaboration and discussion on Business Case G and related uses cases. DER participation under FERC jurisdiction is evolving with required participation at both federal and state regulatory levels. The ISO will continue to support the development of DER integration including improved visibility for grid reliability, as well as pathways for their participation in wholesale markets providing grid supporting services. Pathways for continued efforts in this area include state level proceedings, collaboration with FERC, and ISO stakeholder initiatives for DER policy development.

10.5.10.5 Enphase Consensus, Non-Consensus, and/or Qualifications for Business Case G

Enphase agrees with the growing future need for Fast Frequency Response and synthetic inertia i.e. P as a function of RCOF, P(rcof), as a grid service. That said, we oppose the development of any requirements in advance of a consensus National or International Standard for the function. We believe this will be a critical function in a high DER future but also believe it is essential that it will need to be applied to both DER and controllable loads (smart loads) in order to be effective.

11 Considerations for CPUC Actions

11.1 Assumptions for CPUC Actions

The focus of this SIO Working Group Report is to report on the results of the SIOWG meetings and the documents developed during the SIO process. After this WG report is finalized, the Staff Proposal will develop recommendations for CPUC actions. The Staff Proposal will be developed based on the working group reports, as well as party comments, staff research and analysis, and consultant input. However, it is important for the SIOWG participants to bring their expertise into the process of CPUC actions, since these Business Cases and Use Cases are raising many new issues which do not have clear paths through the regulatory processes. Therefore, this section provides an overview of the recommended CPUC actions.

For the High DER Future, the following assumptions are made for CPUC actions:

- Some proposed CPUC actions could take place in the nearer term, such as for Use Case 1 on scheduling of export limits, while others will require longer terms since they involve new concepts and types of regulations, such as Use Case 4 (Import (Load) Limiting).
- The timeframes for requiring the proposed CPUC actions will reflect the state of the DSO ADMS/DERMS and the DSO communication capabilities, and time for DER testing.
- Since most of the requirements are expected to take effect at the DER facility point of common coupling to the DSO's grid, new testing procedures will need to be developed that not only require testing and certification of individual DER units but also entire facilities at their PCC.
- It is expected that the DSO ADMS/DERMS will have capabilities for assessing short-term forecasts of the distribution grid, such as day-ahead or week-ahead, with hour-ahead possible for some situations or locations.
- It is expected that the DSOs will be capable of using AMI data, telemetry where available, and/or aggregator data as input to these short-term distribution grid forecasts. This implies the need to develop contractual requirements between DSOs and aggregators.
- Although not explicitly captured in this SIOWG process, it is expected that the DSO scheduling, commands, and communications capabilities will also be utilized for other functions, as may be identified in Rule 21 Tariff, IEEE Std 1547-2018, and revisions to IEEE Std 1547, including V1G and V2G.
- It may be that the CPUC treats the “Export” and “Import” requirements together in a new proceeding since distributed energy resources are increasingly combinations of generation and consumption (discharging and charging) such as solar and storage. If so, that may change the detailed CPUC actions described in the subsequent subsections.
- While coordination may be assumed, the CPUC will need to work in collaboration with other entities including CEC, CAISO, and others.

11.2 Proposed CPUC Actions for Use Case 1 “Scheduling Maximum Export Limits”

11.2.1 Add “Firm Export Limits” and “Non-Firm Export Capacity” to Interconnection Agreements

The CPUC will need to initiate a procedure to develop the full understanding of the concepts of “firm export limits” and “non-firm export capacity”, how to add them to Interconnection Agreements, and how DSO grid operations will be able to study, assess different scenarios, and permit DER operators to utilize the non-firm capacity. This procedure will need to:

- Assess the tools required for ICA improvements, short-term power flow applications, and power system monitoring requirements to make sure they are able to support the firm and non-firm concepts, the ability to have more granular timeframes, and the ability to permit non-firm export capacity where and when possible to improve capacity usage. Unused capacity may also need to be addressed to avoid “stranded capacity” (see Annex B).
- Update the screens for assessing interconnections of DER, including the ability to permit the updating of non-firm export capacity schedules for the different purposes and grid conditions.
- Develop the rules for scheduling operational firm export limits and non-firm export capacity related to LGP Interconnection Agreements.
- Develop the rules for updating the schedules for operational firm and non-firm limits for DER facilities to meet abnormal and normal conditions and minimize unused capacity.

Existing resources for scheduling include UL 3141 for testing of Power Control Systems (PCS) that manage DER facility exports and imports.

11.2.2 Upgrade ADMS/DERMS Scheduling Requirements for Export Limiting

The CPUC will need to ensure that DSO ADMS/DERMS applications can support the scheduling requirements for export limiting:

- Define the requirements for scheduling capabilities (see UL 3141 Outline of Investigation for PCS), provisioning, timeframe for adoption, etc.
- Require ADMS/DERMS capability to create, issue/enable, update, and disable schedules for export limiting.

11.2.3 Support Near-Real-Time Communications for Scheduling Export Limits

The CPUC will need to ensure that DSO ADMS/DERMS communications capabilities, including cybersecurity[36], can support the scheduling requirements for export limiting:

- Require the use of AMI, telemetry, and/or aggregator data plus weather and solar forecasts for hour-ahead, day-ahead, and/or week-ahead ADMS/DERMS assessment of export limiting requirements.
- Require the ADMS/DERMS have the capability to issue updates to schedules based on these assessments and on Interconnection Agreement requirements/constraints. These updates could be posted on websites, provided to aggregators, or sent directly to DER facilities.

11.3 Proposed CPUC Actions for Use Case 2 "Commanded Maximum Export Limit"

11.3.1 Upgrade ADMS/DERMS Command Requirements for Export Limiting

The CPUC will need to ensure that DSO ADMS/DERMS applications and communications, including cybersecurity, can support the scheduling requirements for export limiting:

- Require ADMS/DERMS to be capable of issuing commands for firm and non-firm export limiting to DER facility DERMS (FDERMS) and to aggregator DERMS (ADERMS).
- Require FDERMS and ADERMS to manage these commands correctly to meet the export limiting requirement.

11.3.2 Support Near-Real-Time Communications for Commanding Export Limits

The CPUC will need to ensure that DSO ADMS/DERMS communications capabilities, including cybersecurity, can support the scheduling requirements for export commands:

- Require the use of AMI, telemetry, and/or aggregator data plus weather and solar forecasts for hour-ahead, day-ahead, and/or week-ahead ADMS/DERMS assessment of export limiting requirements.
- Require the ADMS/DERMS have the capability to issue commands based on these assessments and on Interconnection Agreement requirements/constraints. These updates could be provided to aggregators or sent directly to DER facilities.

[36] *Smart Inverter Operationalization Cybersecurity Subgroup (SIO-CS) has developed Phase 1 cybersecurity requirements.*

11.4 Proposed CPUC Actions for Use Case 3 "Generation Minimum Export Requirement"

11.4.1 Upgrade ADMS/DERMS Scheduling Requirements for Generation Minimum Export Requirement

The CPUC will need to ensure that DSO ADMS/DERMS applications and communications, including cybersecurity, can support the scheduling requirements for generation minimum export requirement:

- Define the requirements for scheduling capabilities (see UL Outline of Investigation for PCS), provisioning, timeframe for adoption, etc.
- Require ADMS/DERMS capability to create, issue/enable, update, and disable schedules for generation minimum export.

11.4.2 Upgrade ADMS/DERMS Command Requirements for Generation Minimum Export Requirement

The CPUC will need to ensure that DSO ADMS/DERMS communications capabilities, including cybersecurity, can support the scheduling requirements for generation minimum export commands:

- Require ADMS/DERMS to be capable of issuing commands for the use of firm and non-firm generation minimum export requirement.

11.4.3 Support Near-Real-Time Communications for Generation Minimum Export Requirement

The CPUC will need to ensure that DSO ADMS/DERMS communications capabilities, including cybersecurity, can support the scheduling requirements for generation minimum export requirement:

- Require the use of AMI, telemetry, and/or aggregator data plus weather and solar forecasts for hour-ahead, day-ahead, and/or week-ahead ADMS/DERMS assessment of export limiting requirements.
- Require the ADMS/DERMS have the capability to issue schedule updates or commands based on these assessments and on Interconnection Agreement requirements/constraints. The schedule updates could be provided on websites while updates and commands could be provided to aggregators or sent directly to DER facilities.

11.5 Proposed CPUC Actions for Use Case 4 "Import (Load) Limiting"

11.5.1 Develop Procedure for Import Limiting

The CPUC will need to initiate the development of one or more proceedings for firm and non-firm import limiting requirements, including determining any necessary changes to Rule 2, Rule 15, and Rule 16, as well as Rules 29 and 45 for EVs, plus potentially other Rules.

Existing resources include UL 3141 for testing of Power Control Systems (PCS) that manage DER facility exports and imports.

11.5.2 Upgrade ADMS/DERMS Scheduling Requirements for Firm and Non-Firm Import (Load) Limiting

The CPUC will need to ensure that DSO ADMS/DERMS applications and communications, including cybersecurity, can support the scheduling requirements for firm and non-firm import limiting:

- Define the requirements for scheduling capabilities (see UL Outline of Investigation for PCS), provisioning, timeframe for adoption, etc. for import (load) limiting.
- Require ADMS/DERMS capability to create, issue/enable, update, and disable schedules for import limiting.

11.5.3 Upgrade ADMS/DERMS Command Requirements for Firm and Non-Firm Import (Load) Limiting

The CPUC will need to ensure that DSO ADMS/DERMS applications and communications, including cybersecurity, can support the command requirements for import limiting:

- Require ADMS/DERMS be capable of issuing commands for firm and non-firm import (load) limiting.

11.5.4 Support Near-Real-Time Communications for Import (Load) Limiting

The CPUC will need to ensure that DSO ADMS/DERMS communications capabilities, including cybersecurity, can support the communication requirements for load limiting:

- Require the use of AMI, telemetry, and/or aggregator data plus weather and solar forecasts for hour-ahead, day-ahead, and/or week-ahead ADMS/DERMS assessment of import limiting requirements.
- Require the ADMS/DERMS have the capability to issue schedule updates or commands based on these assessments and on Interconnection Agreement requirements/constraints. The schedule updates could be provided on websites while updates and commands could be provided to aggregators or sent directly to DER facilities.
- Require ADMS/DERMS capability to create, issue/enable, update, and disable schedules for import limiting.

11.6 Proceedings, Electric Rules, and Proposed CPUC Actions for Use Cases 1-4

Table 18 presents a high-level cross reference between use case, potential regulatory action, electric rules, and potential proceedings for Business Cases A, B, and C.

Table 18: Regulatory Action to Use Case 1-4 for Business Cases A, B, and C

Regulatory Action, Electric Rule(s), and Potential CPUC Proceedings	Use Case 1 “Scheduling Maximum Export Limits”	Use Case 2 “Commanded Maximum Export Limit”	Use Case 3 “Generation Minimum Export Requirement”	Use Case 4 “Import (Load) Limiting”
Include in Agreements between DSOs and DER owners	**Interconnection Agreement** Add “Firm Export Limits” and “Non-Firm Export Capacity” Add Scheduling capability	**Interconnection Agreement** Add “Firm Export Limits” and “Non-Firm Export Capacity” Add Command capability	**Interconnection Agreement** Add “Firm Export Limits” and “Non-Firm Export Capacity” Add Minimum Export Requirement	**Service Agreement** Add “Firm Import Limits” and “Non-Firm Import Capacity” Add Scheduling capability Add Command capability Add Minimum Import Requirement

Regulatory Action, Electric Rule(s), and Potential CPUC Proceedings	Use Case 1 "Scheduling Maximum Export Limits"	Use Case 2 "Commanded Maximum Export Limit"	Use Case 3 "Generation Minimum Export Requirement"	Use Case 4 "Import (Load) Limiting"
Upgrade ADMS/DERMS Requirements	*Schedule* Maximum Firm and Non-Firm Export Limits	*Command* Maximum Export Firm and Non-Firm Limits	*Schedule* Minimum Export Requirements *Command* Minimum Export Requirements	*Schedule* Requirements for Firm and Non-Firm Import (Load) Limiting and Minimum Import Requirement *Command* Requirements for Firm and Non-Firm Import (Load) Limiting and Minimum Import Requirement
Support Near-Real-Time Communications for Export Limits	*Scheduling* Maximum Export Limits	*Command* Maximum Export Limits *Command* Authorized Non-Firm Capacity	*Scheduling* Minimum Export Limits *Command* Minimum Export Requirements	*Scheduling* and *Commands* on Import Limits
Electric Rule(s)	Rule 21 Tariff	Rule 21 Tariff	Rule 21 Tariff	Rules 2, 15, 16, 25, 49
CPUC Proceedings or Successor Proceedings	*Interconnection Rulemaking* *(R.17-07-007)* *Demand Flexibility Rulemaking* *(R.22-07-005)*	*Interconnection Rulemaking* *(R.17-07-007)* *Demand Flexibility Rulemaking* *(R.22-07-005)*	*Interconnection Rulemaking* *(R.17-07-007)* *Demand Flexibility Rulemaking* *(R.22-07-005)*	*Demand Flexibility Rulemaking* *(R.22-07-005)* *DRIVE Rulemaking (18-12-006)* *New Energization OIR*

11.7 Technology Updates and Estimated Timeframes for Deployment of Use Cases 1-4

Table 19 describes the non-CPUC actions and estimated timeframes that would be required for deployment of Use Cases 1-4 by the different stakeholders and external organizations.

Table 19: Technology Updates and Timeframes for Deployment of Use Cases 1-4

Stakeholders and External Organizations	Use Case 1 "Scheduling Maximum Export Limits"	Use Case 2 "Commanded Maximum Export Limit"	Use Case 3 "Generation Minimum Export Requirement"	Use Case 4 "Import (Load) Limiting"
DSO DERMS development and deployment	Design DERMS power flow applications for assessing available capacity for authorization to use non-firm export capacity. Develop scheduling capability to update authorized non-firm capacity of DER facilities. Develop scheduling capability to reduce firm export limits during abnormal conditions and restore firm export limits upon return to normal. *Estimated timeframe*: 1-2 years after CPUC proceeding decision.	Design DERMS power flow applications for assessing available capacity for authorization to use non-firm export capacity. Develop capability to issue commands to authorize non-firm capacity limits for DER facilities. Develop capability to issue commands to reduce firm export limits during abnormal conditions and restore firm export limits upon return to normal. *Estimated timeframe*: 1-2 years after CPUC proceeding decision.	Design DERMS power flow applications for assessing the requirement or request for minimum export for DER facilities. Use scheduling and/or command capabilities for issuing these minimum export requirements or requests. *Estimated timeframe*: 2-5 years after CPUC proceeding decision.	Design DERMS power flow applications for assessing available capacity for authorization to use non-firm import capacity. Develop scheduling and command capabilities to update authorized non-firm import capacity of DER facilities. Develop scheduling and command capabilities to reduce firm import limits during abnormal conditions and restore firm import limits upon return to normal. *Estimated timeframe*: 3-4 years after CPUC proceeding decision, due to probable lengthy time needed to resolve the regulations on load limiting issues.
DSO ADMS development and deployment	Enhance communications capabilities to monitor more near-real-time data related to capacity on circuits. Provide secure communication capabilities to send updated schedules for DER facilities. Provide secure communication capabilities to send updated schedules to aggregators. *Estimated timeframe*: 1-2 years after CPUC proceeding decision.	Enhance communications capabilities to monitor more near-real-time data related to capacity on circuits. Provide secure communication capabilities to send limit commands to DER facilities. Provide secure communication capabilities to send limit commands to aggregators. *Estimated timeframe*: 1-2 years after CPUC proceeding decision.	Enhance communications capabilities to monitor more near-real-time data related to capacity on circuits. Provide secure communication capabilities to send schedules and/or commands for minimum export requirements and/or requests to DER facilities. *Estimated timeframe*: 2-5 years after CPUC proceeding decision.	Enhance communications capabilities to monitor more near-real-time data related to capacity on circuits. Provide secure communication capabilities to send updated schedules and/or commands for import limiting at DER facilities. Provide secure communication capabilities to send updated schedules to aggregators. *Estimated timeframe*: 3-4 years after CPUC proceeding decision, due to probable lengthy time needed to resolve the regulations on load limiting issues.

Stakeholders and External Organizations	Use Case 1 "Scheduling Maximum Export Limits"	Use Case 2 "Commanded Maximum Export Limit"	Use Case 3 "Generation Minimum Export Requirement"	Use Case 4 "Import (Load) Limiting"
DSO interconnection process	Update interconnection process, power flow study applications, and screens to assess and include optional non-firm export capacity in Interconnection Agreements. *Estimated timeframe*: 1-2 years after CPUC proceeding decision.	Update interconnection process, power flow study applications, and screens to assess and include optional non-firm export capacity in Interconnection Agreements. *Estimated timeframe*: 1-2 years after CPUC proceeding decision.	Include optional minimum export capability in screens for Interconnection Agreements. *Estimated timeframe*: 2-5 years after CPUC proceeding decision.	Update load connection process and power flow study applications to assess and include optional non-firm import capacity in Service Agreements. *Estimated timeframe*: 2-4 years after CPUC proceeding decision.
DSO operational environment	Develop methodology for assessing available capacity for individual circuits and DER facilities. Allocate non-firm export capacity to DER facilities per CPUC rules and their Interconnection Agreements. Send updated schedules of non-firm export capacity to DER facilities. Send schedules reducing firm export limits during abnormal conditions, including restoration to normal firm export limits. *Estimated timeframe for initial deployments:* 2-5 years after CPUC proceeding decision, using a phased process consisting of pilot projects and an initial focus on larger DER facilities. *Estimated timeframe for subsequent deployments*: 5-10 years after CPUC proceeding decision.	Develop methodology for assessing available capacity for individual circuits and DER facilities. Allocate non-firm export capacity to DER facilities per CPUC rules and their Interconnection Agreements. Send commands to authorize non-firm export capacity to DER facilities. Send commands to reduce firm export limits during abnormal conditions, including restoration to normal firm export limits. *Estimated timeframe for initial deployments:* 2-5 years after CPUC proceeding decision, using a phased process consisting of pilot projects and an initial focus on larger DER facilities. *Estimated timeframe for subsequent deployments*: 5-10 years after CPUC proceeding decision.	Develop methodology for determining the need for minimum export requirements or requests. Allocate minimum export requirements to DER facilities. Allocate minimum export requests, including incentives, to DER facilities. Send schedules and/or commands for minimum export requirements or requests. *Estimated timeframe for initial deployments:* 3-5 years after CPUC proceeding decision, using a phased process consisting of pilot projects and an initial focus on larger DER facilities. *Estimated timeframe for subsequent deployments*: 5-10 years after CPUC proceeding decision.	Develop methodology for assessing available capacity for individual circuits and DER facilities. Allocate non-firm import capacity to DER facilities per CPUC rules and their Service Agreements. Send updated schedules and/or commands of non-firm import capacity to DER facilities. Send schedules and/or commands for reducing firm import limits during abnormal conditions, including restoration to normal firm import limits. *Estimated timeframe for initial deployments:* 3-5 years after CPUC proceeding decision, using a phased process consisting of pilot projects and an initial focus on larger DER facilities. *Estimated timeframe for subsequent deployments*: 5-10 years after CPUC proceeding decision.

Stakeholders and External Organizations	Use Case 1 "Scheduling Maximum Export Limits"	Use Case 2 "Commanded Maximum Export Limit"	Use Case 3 "Generation Minimum Export Requirement"	Use Case 4 "Import (Load) Limiting"
UL for safety testing and certification	Continue development of UL 3141[37] which provides requirements for testing PCS export and import limiting. Update testing requirements for scheduling in UL 3141 to handle non-firm and firm export schedules. *Estimated timeframe:* 1-2 years.	Continue development of UL 3141 which provides requirements for testing PCS export and import limiting. Update testing requirements for commands in UL 3141 to handle non-firm and firm export schedules. *Estimated timeframe:* 1-2 years.	Update UL 1741 to include testing of minimum export requirements. *Estimated timeframe:* 2-3 years, pending priority relative to export limits.	Continue development of UL 3141 which provides requirements for testing PCS export and import limiting. Update testing requirements for scheduling in UL 3141 to handle non-firm and firm import schedules. *Estimated timeframe:* 1-2 years.
DER vendors and implementors	Design and implement DER systems and/or Power Control Systems to utilize firm export limits and authorized non-firm export capacity at an RPA. Implement the use and updating of schedules for export limiting. Type-test and site test DER systems and/or PCS to meet the requirements for managing scheduled export firm and non-firm limits. *Estimated timeframe*: 2-5 years after CPUC proceeding decision.	Design and implement DER systems and/or Power Control Systems to utilize firm export limits and authorized non-firm export capacity at an RPA. Implement the response to commands for export limiting. Type-test and site test DER systems and/or PCS to meet the requirements for managing commanded export firm and non-firm limits. *Estimated timeframe*: 2-5 years after CPUC proceeding decision.	Design and implement DER systems and/or Power Control Systems to meet the minimum export requirements and/or respond to minimum export requests. Type-test and site test DER systems and/or PCS to meet the requirements for managing minimum export requirements. *Estimated timeframe*: 3-5 years after CPUC proceeding decision.	Design and implement DER systems and/or Power Control Systems to utilize firm import limits and authorized non-firm import capacity at an RPA. Implement the use and updating of schedules or responding to commands for import limiting. Type-test and site test DER systems and/or PCS to meet the requirements for managing scheduled import firm and non-firm limits. *Estimated timeframe*: 3-5 years after CPUC proceeding decision.

11.8 Proposed CPUC Action for Business Case E "EVs Provide Distribution Services for Grid Support"

The Business Case E Use Cases were provided to the CPUC group working on electric vehicles. The most recent decision on electric vehicles as DER is in Decision 20-09-035 September 24, 2020, Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21 Tariff. Rulemaking 17-07-007, "*Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup*". Section 3.3 addressed "*V2G AC Subgroup Issues: Process for Monitoring Development of Standards for Interconnection of Mobile Inverters*":

[37] *UL 3141 scope: These requirements cover Power Control Systems (PCS) used in Distributed Energy Resource (DER) systems which include one or more power sources in addition to the primary power source, typically the utility grid. PCS-LC (load control only applications) may consist of only the utility source, or a combination of the utility source and DER sources not controlled by the PCS-LC sized per 705.12 of NFPA 70. The PCS electronically limits or controls currents to stay within defined limits and may consist of a single device or multiple devices operating together as a system. The current or power measurement reference point(s) may be located internally to equipment or externally within the system.*

- *Issue 1. The V2G AC Subgroup shall: a) complete the mapping of existing standards from nationally-recognized testing laboratories against each other and b) determine how well the existing standards can be combined to fulfill safety requirements for interconnection of a mobile inverter at one fixed point.*
- *Issue 2. If existing standards are sufficient for safe interconnection, the subgroup may recommend that the Commission include language citing existing standards to enable Rule 21 Tariff interconnection.*
- *Issue 3. If existing standards are not sufficient, the subgroup should notify the testing laboratories to inform them of the gap in standards.*

After review by this group of the EV Use Cases, the next steps could be:

- Determine if the CPUC should undertake any rulings on EVs as DERs:
  - V1G as part of load limiting (see Use Case 4).
  - V2G on permission to export power to the grid if the charging source had been renewable and/or if additional generation is needed during emergency conditions (see Business Case B).
  - What qualifications or changes to Rule 21 Tariff could or should be made for EVs (and/or storage DER) to provide grid services when they are charging (see Business Case C).[38]
- Communications with EVs may entail different protocols, partly because OCPP is more frequently used for interactions with EVSEs, and partly because EV OEMs have their own proprietary communications with their EVs.

This proposed process is still in progress and should be addressed as part of the "generation and consumption" combined issues related to any DER system that includes storage.

11.9 Proposed CPUC Action for Business Case G: "Provide ISO Grid Services using DER"

The Business Case G Use Cases were provided to CAISO for their review and comment. These comments have been incorporated in this WG Report. Therefore, no further actions by the CPUC are necessary, other than continuing coordination.

11.10 Rules, Proceedings, and Proposed CPUC Actions for Business Cases E, F, and G

Table 20 presents a high-level cross reference between business cases, electric rules, potential proceedings, and other agencies that would need to take up ownership to implement Business Cases E, F, and G

Table 20: Electric Rules, Proceedings, and Other Agency Ownership for Business Cases E, F, and G

Electric Rule(s), Potential CPUC Proceedings, Other Agencies Ownership	Case E: Operational Flexibility for Electric Vehicles Providing Distribution Services	Business Case F: Operational Flexibility in Community Microgrids	Business Case G: Operational Flexibility for DER Providing ISO Grid Services
Electric Rule(s)	21, 25/49	21	

[38] *Inclusion of charging may be added to Rule 21 Tariff in the future if IEEE 1547 revision includes charging. There ought not be a difference in the functions provided just because they are charging, not discharging.*

Electric Rule(s), Potential CPUC Proceedings, Other Agencies Ownership	**Case E: Operational Flexibility for Electric Vehicles Providing Distribution Services**	**Business Case F: Operational Flexibility in Community Microgrids**	**Business Case G: Operational Flexibility for DER Providing ISO Grid Services**
CPUC Proceedings or potential successor Proceedings where Implementation Might be Applicable	*DRIVE Rulemaking (18-12-006)* *New Energization OIR*	*Interconnection Rulemaking* *(R.17-07-007)* *Demand Flexibility Rulemaking* *(R.22-07-005)* Microgrids and Resiliency Strategies Rulemaking (R 19-09-009) *New Energization OIR*	
Other Agency Ownership			*CAISO*

12 Conclusion

The SIOWG has worked very hard to come to general consensus on these Business Cases and Use Cases, albeit with very necessary qualifications on what the next steps need to be. Those qualifications will need to be discussed and amplified during subsequent proceedings, based on the Staff Proposal recommendations.

Annex A History of Smart Inverter Functions

A.1 History of the Smart Inverter Working Group (SIWG)

The Smart Inverter Working Group (SIWG) grew out of a collaboration between the CPUC and California Energy Commission (CEC) in early 2013 that identified the development of advanced inverter functionality as an important strategy to mitigate the impact of high penetrations of distributed energy resources (DERs). At that time, DER systems (typically small photovoltaic systems that did not normally export power) were just considered as “negative load” which off-set some of the load of their owners. However, it was clear that even these small residential PV systems could export significant amounts of energy during the middle of the day, and that even the larger commercial and industrial PV systems were also being interconnected to the distribution system.

During the first meetings of the SIWG, this realization triggered the concerns of the DSOs on the PV impacts on grid stability and reliability, and they first focused on just limiting the size of PV systems but, with pressure from the DER manufacturers and aggregators, recognized that by making use of the PV inverters, many of their concerns could be minimized. So, it became more an engineering question of what functions would be required and what the parameters of those functions should be to minimize any negative impacts on grid reliability.

The SIWG pursued the development of advanced inverter functionality over three phases. Phase 1 focused on autonomous functions (not requiring communications with the DSO) to respond to grid conditions and take ameliorating actions. Phase 2 considered the default protocols for communications between IOUs, DERs, and DER aggregators. Phase 3 added some more advanced inverter functionality for more flexible responses to the grid conditions, with some functions relying on the Phase 2 communications capabilities.

Once the 3 phases had been initially defined, it was clear that time was required for developing testing requirements and for allowing the manufacturers to go through the testing procedures for these functions. In addition, particularly as DER systems started to be implemented with these functions, many new questions arose on how and when the functions should be used. At the same time, energy storage systems became increasingly prevalent, often paired with the PV systems. And as higher penetrations of larger DER installations became the norm, new issues arose on how to actively manage these DER since purely autonomous responses to local grid conditions were no longer adequate.

Nationally, it became recognized that the issue of DER was not just a California problem but that these DER could impact all distribution systems as DER proliferated. Therefore, the IEEE SC21 undertook to update the IEEE Std 1547 standard on DER interconnections, resulting in the publication of IEEE Std 1547-2018.

The SIWG continued to discuss and refine the functions, based on issues raised by the various stakeholders. Many issues were resolved but some still were open and required additional workshops (see section A.4) to understand and resolve these issues. The SIWG also decided to use the IEEE Std 1547-2018 requirements to augment the functions defined in Rule 21 Tariff, which was achieved in 2023.

A.2 SIWG Phases of Rule 21 Tariff Functions

A.2.1 SIWG Phase 1

The SIWG Phase 1 identified autonomous functions that all inverter-based DER units in California are required to perform. Those requirements were included in Rule 21 Tariff in 2015, but before these functions could be implemented, the type-testing and certification procedures had to be established. Therefore, UL added a supplementary section to its UL 1741 DER safety certification, called UL 1741 Supplement A (UL 1741 SA). Once that document was finalized, DER manufacturers were given some time to go through type-testing of their equipment, and then Phase 1 went into effect on September 9, 2017.

It is important to note that these Phase 1 functions were designed to be autonomous, namely that no communications were required since the functions would be integrated into the controllers of individual DER units by the manufacturers, type-tested according to UL 1741 SA at the Point of Connection (PoC) and implemented as is in the field (see Figure 31). These autonomous functions were not expected to utilize communications since their parameters were fixed by Rule 21 Tariff.

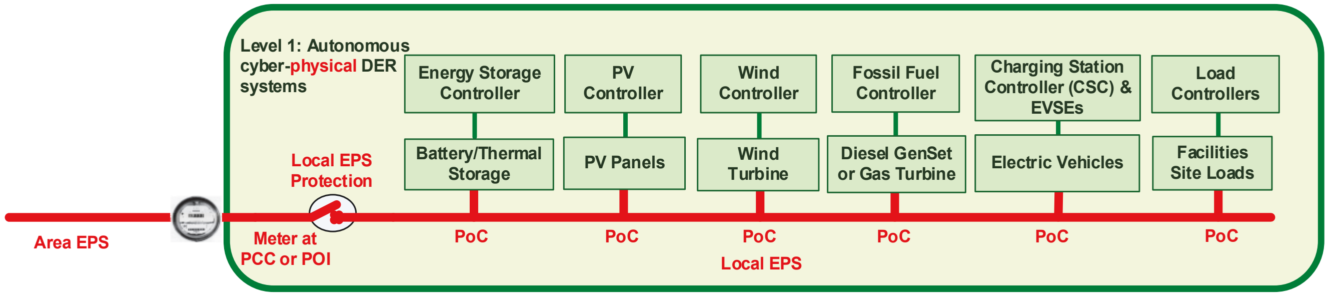

Figure 31: DER units, their PoCs, and the PCC at the meter

The functions in Phase 1 are:

- **Anti-islanding (Non-Islanding):** A control scheme installed as part of the Generating or Interconnection Facility that senses and prevents the formation of an Unintended Island.
- **High/Low Voltage Ride-Through function:** The DER rides through temporary fluctuations in voltage by following the DSO-specified voltage ride-through parameters to avoid tripping off unnecessarily. The function would block tripping within the fault ride-through zones. Although normally enabled by default, this ride-through operational function may be updated, enabled, and disabled. Rule 21 Tariff Table Hh-1 defines the voltage ride-through settings.
- **High/Low Frequency Ride-Through function:** The DER rides through temporary fluctuations in frequency by following the DSO-specified frequency ride-through parameters to avoid tripping off unnecessarily. The function would block tripping within the fault ride-through zones. Although normally enabled by default, this ride-through operational function may be update, enabled, and disabled. Rule 21 Tariff Table H.2 defines the frequency trip settings.
- **Volt-Var Control function:** The DER responds to changes in voltage at the RPA by supplying or absorbing reactive power in order to maintain the desired voltage level. The DER is provided with voltage-var curves that define the reactive power for voltage levels. When the volt-var operational function is enabled, the DER receives the voltage measurements from a meter (or another source) at the RPA. The DER responds by supplying or absorbing reactive power according to the specified volt-var curve in order to maintain the desired voltage level. Rule 21 Tariff Table Hh-4 and Figure Hh-1 define the voltage and reactive default settings.
- **Ramp rates (ramp times):** Default and emergency ramp times are set. The active power should be at the required power level by the end of the ramp time. It may reach the required power level earlier, but not later. Rule 21 Tariff section Hh.2.k defines the ramp rate requirements.
- **Fixed power factor:** The DER power factor is set to the specified power factor. A leading power factor is positive, and a lagging power factor is negative, as defined by the IEEE or IEC sign conventions. Rule 21 Tariff section Hh.2.i defines the fixed power factor requirements.
- **Reconnect by "soft-start" methods**: Use a specific ramp rate and/or a random time within window when reconnecting.

The default activation states are shown in Table 21.

Table 21: SIWG Phase 1 Default Activation States

Function	State
Anti-islanding	Activated
Low/High Voltage Ride Through	Activated
Low/High Frequency Ride Through	Activated
Dynamic Volt/Var operations	Activated
Ramp rates	Activated
Fixed power factor	Deactivated
Reconnect by "soft-start" methods	Activated
Frequency/Watt[i]	Activated
Volt/Watt[i]	Activated
Set Active Power Function Mode(Optional)	Activated under mutual agreement
Dynamic Reactive Power Support Mode (Optional)	Activated under mutual agreement

A.2.2 SIWG Phase 2

After lengthy discussions on available communication protocols such as IEEE 1815 (DNP3), IEC 61850, and Modbus, the IEEE 2030.5 communications protocol was selected as the default protocol in Rule 21 Tariff, with detailed specifications defined in the Common Smart Inverter Profile (CSIP) (2015-2016). Other application-level protocols could be used by mutual agreement of the parties including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850.

Eventually (2019) Rule 21 Tariff was updated, stating the Phase 2 communications requirements may be met by any of the four options prescribed in Rule 21 Tariff section Hh.5 (IEEE 2030.5, IEEE 1815 (DNP3), SunSpec Modbus, or IEEE 61850). It further clarifies that the Phase 2 requirements do not require IEEE 2030.5 capabilities at the inverter level. This latter ruling implies that Phase 2 communications requirements would not necessarily apply to the DER unit PoCs but could apply between the DSO and the DER facility's PCC, as shown as red lines in Figure 32. In fact, the dotted blue lines between the Gateways/EMS and the DERs are usually Modbus.

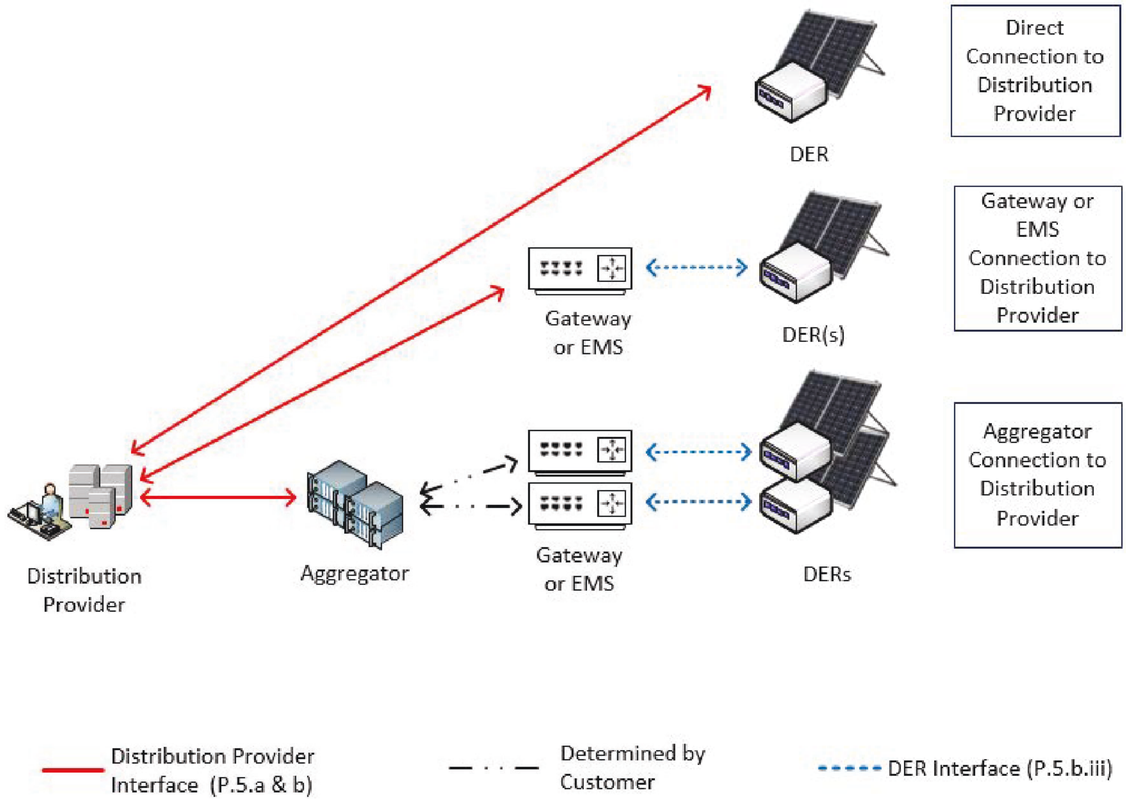

Figure 32: Rule 21 Tariff Communication Alternative Protocols

A.2.3 SIWG Phase 3

The following SIWG Phase 3 functions were included in Rule 21 Tariff with some clarifications and modifications over time.

- **Monitor Key DER Data (Currently one-way telemetry only)** (Function 1): Monitor critical active power, reactive power, voltage, etc., from key DER installations, typically those > 1 MW. This telemetry is currently one-way only, from the DER site to the DSO. Thus, commands and setting changes from the DSO to the DER site are not currently included (unless the DSO is authorized to manage the DER systems).

- **DER Disconnect/ Reconnect (Trip or Cease to Energize/Enter service)** (Function 2): The disconnect command initiates the galvanic separation (usually via switches or breakers) of the DER at the Reference Point of Applicability (RPA) (typically at its POC or at the PCC). There may be a time delay between receiving the command and the actual disconnect. Disconnects from the grid are typically required to avoid unintentional islands, to correct unsafe operating conditions, if the frequency or voltage is outside the time range during a ride-through situation, or due to other emergency situations. It is expected that this disconnect and reconnect will be handled locally through protection equipment or remotely by an aggregator, not via a DSO command.

  “Cease to energize” is a different function from disconnect/connect. The (draft) definition is “the DER shall not export active power during steady-state or transient conditions. Reactive power exchange (absorb or supply) shall be less than x% of nameplate DER rating and shall exclusively result from passive devices.”. There may be a time delay between receiving the command and the actual cease to energize.

  “Return to service” or connect command initiates or allows the reconnection of the DER at its POC or at the PCC. Permission to reconnect may also need to be issued.

- **Limit Maximum Active Power (Export Limiting)** (Function 3): The production and/or consumption of the DER is limited at the Reference Point of Applicability (RPA), indicated as absolute watts values. Separate parameters are provided for production or consumption limits to permit these to be different. Alternatively, a certified Power Control System (PCS) at the DER site can be used to limit export at the PCC, based on a schedule (see Scheduling Function 8) or on command.
- **Set Active power** (Function 4): The DER is set to an active power value or a percentage of maximum generation or consumption rate. In the generation frame of reference, a positive value indicates generation, negative means consumption. This function is primarily applicable to energy storage systems and/or fossil fuel generators. It is currently optional and was recently addressed in SIWG, but no specific requirements were developed.
- **Frequency-Watt** (Function 5): The frequency-watt function requires the DER to modify its active power output or input, based on the frequency. This function can be used for many purposes, such as Droop, Fast-Frequency Response, Artificial Inertia, and Frequency Smoothing. In Rule 21 Tariff it is used to mitigate over- and under-frequencies before and during frequency ride-through events.

  When system frequency exceeds 60.036 Hz, the active power output produced by the Smart Inverter shall be reduced by 50% of real power nameplate rating per hertz (5% of real power nameplate rating reduction per 0.1 hertz). When system frequency moves under 59.964 Hz, the active power output produced by the Smart Inverter shall be increased by 50% of real power nameplate rating per hertz (5% of real power nameplate rating increase per 0.1 hertz) when inverter is capable of increasing active power output.

  Droop is also a frequency-watt control mode used for AC electrical power generators to maintain the frequency within the normal operating zone, focused on returning the frequency to its nominal value (e.g. 50 Hz or 60 Hz). Specifically, the active power output of a generator reduces as the line frequency increases above nominal frequency, and vice versa. It is commonly used as the speed control mode of the governor of a prime mover driving a synchronous generator connected to an electrical grid.
- **Volt-Watt** (Function 6): The DER is provided with voltage-watt parameters that define the changes in its active power output or input, based on voltage deviations from nominal, as a means for countering those voltage deviations.

  In Rule 21 Tariff, when the measured voltage is greater than 106% of nominal voltage (Example: 127.2 volts on a 120 volts nominal), the export of active power at the PCC or the production of active power by the Smart Inverter shall be reduced at a rate of 25% of active power nameplate rating per one percent of nominal voltage. When the measured voltage is greater than 110% of nominal voltage (Example: 132 volts on a 120 volts nominal), the export of active power to the grid at the PCC or the production of active power by the Smart Inverter shall be reduced to 0 watts. This function does not address active power input.
- **Dynamic Reactive Support** (Function 7): The DER provides dynamic reactive current support in response to voltage spikes and sags, similar to acting as inertia against rapid changes. This function may be focused on emergency situations or may be used during normal operations. It is optional in Rule 21 Tariff, pending a more standardized definition of its requirements.
- **Scheduling** Power Values and Modes (Function 8): Scheduling is an actively discussed capability since it is needed by the Limited Generation Profile (LGP) proceeding in the SIWG. Some basic scheduling capabilities have recently become part of UL 3141 Outline of Investigation for use with Limit Active Power. In Rule 21 Tariff the only scheduling requirement is the ability to store 24 events.

Communications were expected to be needed by the SIWG Phase 3 requirements as illustrated in Figure 33.

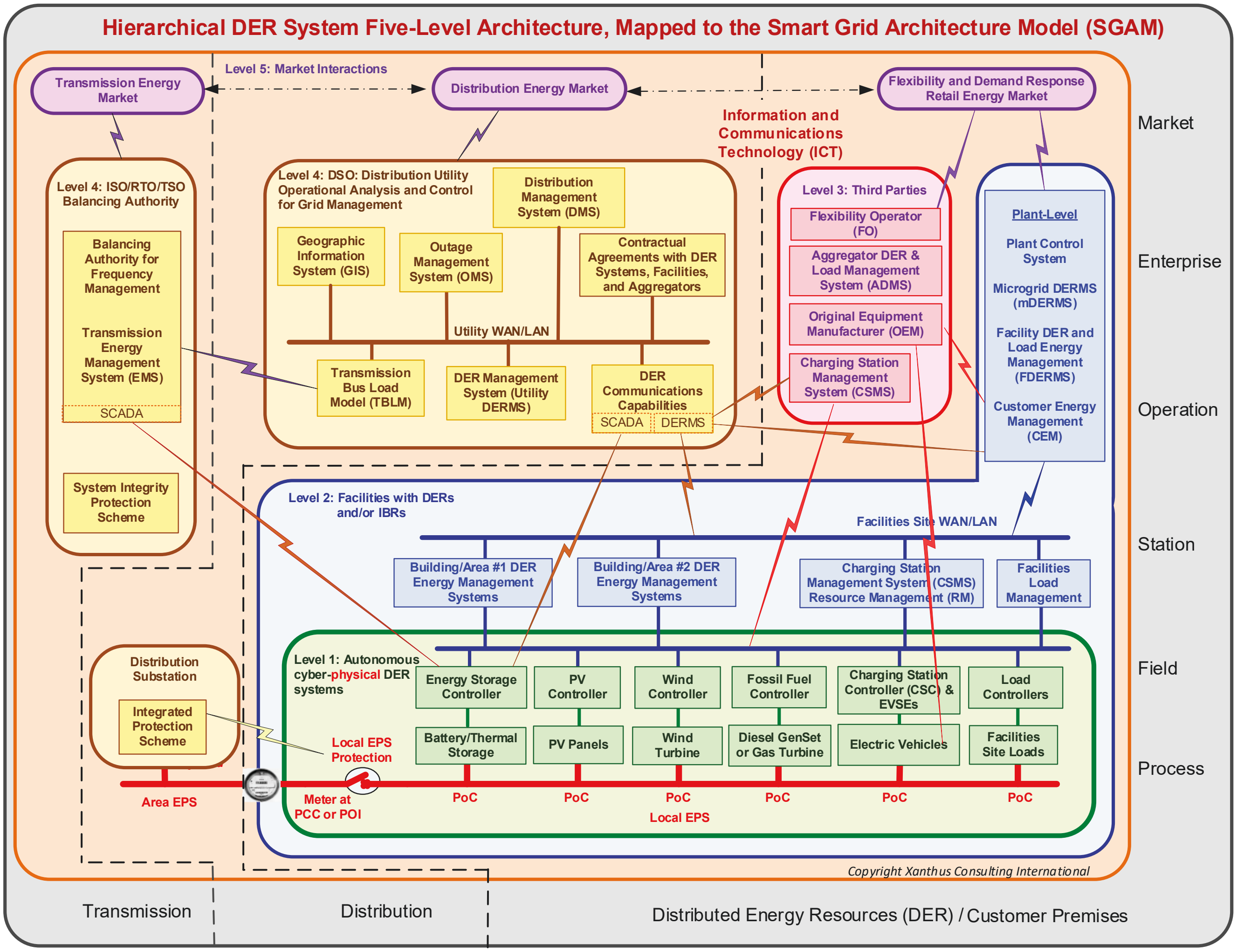

Figure 33: DER units (green), DER facilities (blue), Aggregators (red), DSO & TSO (yellow), and Markets (purple)

A.3 IEEE Std 1547-2018 into Rule 21

In 2023, Rule 21 Tariff adopted the IEEE Std 1547-2018 set of functions, their parameters, and the communication requirements (for the most part). These functional requirements either replaced or added to the functional requirements identified in the SIWG Phase 1, 2, & 3. The IEEE Std 1547-2018 functions are listed below:

- Monitor key configuration, status, and measurement data (plus state of charge for storage systems)
- Connect/disconnect from the grid
- Cease to Energize/ Enter Service
- Voltage Ride-Through
- Frequency Ride-Through
- Dynamic Reactive Current Support (optional)
- Frequency-Watt (Primary Frequency Response (PFR or Droop))
- Volt-Watt Mode

- Constant Power Factor Mode
- Constant Reactive Power
- Volt-Var Mode
- Watt-Var Mode
- Limit Active Power
- Set Active Power (included in IEEE Std 1547.9 for storage)
- Retrieve nameplate information (per factory)
- Retrieve operational settings (as built)
- Transitioning to and from islanded condition

IEEE Std 1547-2018 requirements also identified IEEE Std 1547.1 and UL 1741 Supplement B as the testing requirements. It should be noted that IEEE Std 1547 is now being updated with an expected publishing date of 2025/2026.

A.4 SIWG Workshops to Resolve Issues

On July 13, 2017, the California Public Utilities Commission (CPUC or Commission) issued an Order Instituting Rulemaking to consider a variety of refinements to the interconnection of distributed energy resources under Electric Rule 21 Tariff. On October 2, 2017, the Commission issued a scoping ruling for R.17-07-007 directing Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E), or the investor-owned utilities (IOUs or utilities), to convene eight working groups to develop proposals to address the issues.

Working Group One submitted its final report on March 15, 2018. Working Group Two submitted its final report on October 31, 2018. Working Group Three submitted its final report on June 14, 2019.

An amended scoping memo issued on November 16, 2018, originally tasked Working Group Four to address four issues (18, 19, 29, and F), commencing on a date to be determined. An Administrative Law Judge's ruling on November 27, 2019, established the commencement of Working Group Four as February 2020. A workshop notice was filed on January 31, 2020, announcing the commencement of Working Group Four with a workshop on February 12, 2020. The duration of the Working Group was set at six months from this date.

Ultimately those workshops recommended the establishment of a Smart Inverter Operationalization Working Group (SIOWG). That led to the CPUC including the SIOWG in the "Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future" (R21-06-017).

Annex B Handling of Unused Capacity

B.1 Discussion in SIOWG on Unused Capacity

As the SIOWG discussed operational flexibility as a means to utilize available capacity in the distribution system more effectively, the focus was on the DSOs assessing congested circuits in order to allow DERs to export more power and/or loads to import more power. However, the reverse side of that operational flexibility is how DER owners/operators might have been allocated more export capacity than they use. Equivalently, some customers may have been allocated more import capacity than they use.

Over short term time periods, this unused capacity could be seen as just the normal fluctuations in generation and load. However, over long term time periods, this unused capacity could be limiting other customers from utilizing the circuits' actual capacity more effectively. This unused capacity could be termed "stranded capacity".

B.2 Possible Methods for Handling Unused Capacity

Although this topic of unused capacity was not addressed in great detail, a number of possible methods for handling it was discussed:

1. **Do nothing:** the allocation of export or import capacity is in formal Interconnection Agreements or Limited Load Profiles, so contractually the DSO cannot do anything.
2. **Customer forecasts of their exports and/or imports:** the customer is requested or required to provide forecasts of their planned exports and/or imports to the DSO, who can then choose to allocate any unused capacity to other customers.
3. **Customer requests the DSO to authorize specific amounts of non-firm export or import capacity:** the DSO can then choose to authorize up to that requested amount and then allocate any available unused capacity to other customers.
4. **Claw back unused capacity:** if the customer never uses or cannot utilize their allocated capacity, after a period of time, that unused capacity is clawed back. This claw-back provision could be part of the original interconnection or Limited Load Profile.
5. **Customer issues a capacity release of some of their firm and/or authorized non-firm capacity**: the customer can either release the capacity back to the DSO for compensation or use it in a secondary market if that exists.

This issue of unused capacity could be addressed more fully in a future proceeding.

Annex C List of All Use Cases Discussed in the SIOWG

C.1 Business Case A: Operational Flexibility in DER Interconnection Agreements

- Use Case A1. Scheduled Maximum Export Limit in Interconnection Agreements
  - Sub Case A1a: The DSO includes a schedule of firm export limits plus non-firm export capacity in the Interconnection Agreement, based on ICA. (Schedule granularity may change pending decisions from 5211 SIWG Workshops)
  - Sub Use Case A1b: Include in the Interconnection Agreement the ability to modify schedules of operational export limits (firm limits plus authorized non-firm capacity) by time of day and by day of week. This increased granularity would be based on more granular assessments of actual capacity.
  - Sub Use Case A1c: Include in the Interconnection Agreement the ability to modify schedules of operational export limits by day-ahead and/or hour-ahead. This capability could be used for DSO planned actions and/or n-1 contingency analysis.
- Use Case A2. Commanded Maximum Export Limit in Interconnection Agreements
  - Sub Use Case A2a: Include in the Interconnection Agreement the ability for the DSO to issue commands that authorize additional operational export limits.
  - Sub Use Case A2b: Include in the Interconnection Agreement the ability of the DSO to command the decrease of operational export limits, including firm limits, due to reconfiguration, maintenance, or emergency.
- Use Case A3. Minimum Generation Export Requirement in Interconnection or other Agreements
  - Sub Use Case A3a: Include in the Interconnection Agreement the ability of the DSO to set the exact operational export limit at the PCC via the Set Active Power function.
  - Sub Use Case A3b: Include in the Interconnection Agreement the ability of the DSO to request a minimum operational export limit at the PCC.
  - Sub Use Case A3c: Include in the Interconnection Agreement the ability of the DSO to set the active power output of a DER at the DER's Point of Connection. This Sub Use Case may be very similar functionally to Sub Use Case A3a but implies communications with the DER rather than communications to an aggregator or Power Control System (PCS).
- Use Case A4. Maximum Import (Load) Limit in Limited Load Profiles
  - Sub Use Case A4a: Include in the Limited Load Profile the ability of the DSO to schedule the maximum operational import limit (firm import limit plus authorized non-firm import capacity) at the PCC. This Sub Use Case is the equivalent to the scheduling of export limits but applies to load import limits.
  - Sub Use Case A4b: Include in the Limited Load Profile the ability of the DSO to command maximum operational import limit at the PCC. This Sub Use Case is the equivalent to the commanding of export limits but applies to load import limits.
- Use Case A5. Situational Awareness in Interconnection or Limited Load Profiles
  - Sub Use Case A5a: Include in the Interconnection or Limited Load Profile the ability for the exchange of information between the DER and the DSO within a day, not necessarily with communications protocol (e.g. with AMI). This AMI data could be used not just for verification of compliance, but also the analysis of actual capacity and reliability issues of the circuit.

- Sub Use Case A5b: Include in the Interconnection or Limited Load Profile the ability for the exchange of information between the DER and the DSO within an hour, using a communications protocol. Currently this applies to larger DER (e.g. > 1 MW), but may be extended to apply to additional DER.
- Sub Use Case A5c: Include in the Interconnection or Limited Load Profile the ability for the exchange of information between the DER and the DSO within 5 minutes, using communications protocol, using a communications protocol. Currently this applies to larger DER (e.g. > 1 MW), but may be extended to apply to additional DER.
- Sub Use Case A5d: Include in the Interconnection or Limited Load Profile the ability for the exchange of information between the DER and the DSO within one second, using a communications protocol capable of SCADA interactions. This would typically apply to specific DER in which the DSO has the authority to monitor and/or manage the DER in real-time.

C.2 Business Case B: Operational Flexibility during Abnormal Conditions

- Use Case B1. Scheduled Maximum Operational Export Limit in Emergency Conditions
  - Sub Case B1a: A schedule of limits is included in the Interconnection Agreement as an Emergency Schedule to take effect during emergencies that may be foreseen (e.g. wildfires, heat waves, n-1 overload contingencies), and to be triggered by an automated response to grid frequency or voltage, protective relaying, a communication command, an emergency text signal, a phone call, or some other "near-real-time" trigger.
  - Sub Use Case B1b: The operational schedule of limits includes time of day and day of week for use during emergency situations. Triggering may be by an automated response to grid frequency or voltage, protective relaying, a communication command, an emergency text signal, a phone call, or some other "near-real-time" trigger.
  - Sub Use Case B1c: DSO updates the operational schedule by day-ahead and/or hour-ahead in anticipation of possible emergencies. Triggering may be by an automated response to grid frequency or voltage, protective relaying, a communication command, an emergency text signal, a phone call, or some other "near-real-time" trigger.

- Use Case B2. Commanded Maximum Operational Export Limit in Emergency Conditions
  - Sub Use Case B2a: DSO issues a command to override any scheduled operational export limits in order to allow additional generation export, (e.g. if more generation is needed due to an emergency). This Sub Use Case is similar to Sub Use Case B3a, except permission is given for additional export rather than a requirement for a specific export level.
  - Sub Use Case B2b: DSO issues a command to decrease the operational export limit due to an emergency situation (e.g. if less generation is needed due to an emergency). This Sub Use Case is similar to Sub Use Case B3a, except this issues a lower export limit rather than a requirement for a specific export level.
- Use Case B3. Minimum Generation Export Requirement in Emergency Conditions
  - Sub Use Case B3a: DSO issues command to set an exact operational export level at the PCC via the Set Active Power function. This command reflects an emergency need for a specific amount of generation export.
  - Sub Use Case B3b: DSO issues a command for requiring a minimum operational export level at the PCC. This Sub Use Case is the opposite of Sub Use Case B2b in that it requires at least a minimum

level of export. This command reflects an emergency need for at least the minimum amount of generation export.

  - Sub Use Case B3c: DSO issues a command to set the exact active power output of a DER at the DER's Point of Connection. This Sub Use Case may be very similar functionally to Sub Use Case B3a but implies communications with the DER rather than communications to an aggregator or Power Control System (PCS).

- Use Case B4. Maximum Import (Load) Limit in Emergency Conditions
  - Sub Use Case B4a: DSO provides a schedule for maximum operational import (load) limits during emergencies (e.g. wildfires, heat waves, n-1 contingencies), to take effect during emergencies. Triggering may be by an automated response to grid frequency or voltage, protective relaying, a communication command, an emergency text signal, a phone call, or some other "near-real-time" trigger.
  - Sub Use Case B4b: DSO issues a command to limit the operational import (load) during an emergency. Triggering may be by an automated response to grid frequency or voltage, protective relaying, a communication command, an emergency text signal, a phone call, or some other "near-real-time" trigger.

- Use Case B5. Situational Awareness in Emergency Conditions
  - Sub Use Case B5a: DSO collects data from the grid and DER at the PCC within a day, not necessarily with a communications protocol (e.g. could be collected via an Advanced Metering Infrastructure (AMI) system), in order to capture active power export, import, demand, outages, and other data for future analysis.
  - Sub Use Case B5b: DSO collects alarm and event logs from the grid and DER at PCC within an hour, using a communications protocol, to capture data for near-real-time analysis of the emergency situation.
  - Sub Use Case B5c: DSO monitors grid and DER export, import, frequency, voltage, and other data at PCC within 5 minutes, using a communications protocol, for possible use in near-real-time responses to an emergency situation.
  - Sub Use Case B5d: DSO monitors data from the grid and the DER at PCC within one second, using a communications protocol, with the capability to issue real-time commands during an emergency situation.

C.3 Business Case C: Operational Flexibility for Distribution Services under Normal Conditions

- Use Case C1. Scheduled Maximum Operational Export Limit for Distribution Services
  - Sub Case C1a: Update the schedule of maximum operational export limits to reflect updated capacity analysis (Schedule granularity may change pending decisions from 5211 SIWG Workshops). These updates may reflect the results of more recent analyses or changed grid conditions. If the updates exceed any ranges of export limits provided for flexibility in the original Interconnection Agreement, a new Interconnection Agreement will need to be negotiated.
  - Sub Use Case C1b: DSO increases the granularity of the scheduled maximum operational export limits by time of day and by day of week, within the constraints of the firm limits and non-firm capacity in the Interconnection Agreement. These updates may reflect the results of more recent analyses or changed grid configurations and may potentially provide additional capacity to provide distribution services.

- Sub Use Case C1c: DSO updates the scheduled maximum operational export limits for day-ahead and/or hour-ahead timeframes, within the constraints of the Interconnection Agreement. These updates may reflect the results of planning for contingencies, planning for scheduled actions, more recent power flow analyses, or changed grid configurations, and may potentially provide additional capacity to provide distribution services.

- Use Case C2. Commanded Maximum Operational Export Limit for Distribution Services
  - Sub Use Case C2a: DSO issues a command to allow additional operational export by authorizing some non-firm export capacity, thus increasing the maximum operational export capacity. These updates may reflect the results of planning for contingencies, planning for scheduled actions, more recent power flow analyses, or changed grid configurations, and may potentially provide additional capacity to provide distribution services.
  - Sub Use Case C2b: DSO issues a command to decrease the maximum operational export capacity, within constraints of Interconnection Agreement. These updates may reflect the results of contingency analyses or planned actions, thus potentially mitigating problems during reconfiguration, planned maintenance, switching operations, and other distribution services.
- Use Case C3. Minimum Operational Export Requirement for Distribution Services
  - Sub Use Case C3a: DSO issues a command to set an exact export level of generation at the PCC via the Set Active Power function.
  - Sub Use Case C3b: DSO issues a command for requiring a minimum export level of generation at the PCC. This Sub Use Case is the opposite of Sub Use Case C2b in that it requires at least a minimum level of export.
  - Sub Use Case C3c: DSO issues a command to set a fixed generation level at a DER unit's Point of Connection. This Sub Use Case may be very similar functionally to Sub Use Case C3a but implies communications with the DER unit rather than communications to an aggregator or power plant Power Control System.
- Use Case C4. Maximum Operational Import (Load) Limit for Distribution Services
  - Sub Use Case C4a: DSO provides a schedule for maximum operational import (load) limits, within the constraints included in the Limited Load Profile. This Sub Use Case is the equivalent to the scheduling of generation export limits but applies to load import limits. These limits may reflect the results of planning for contingencies, planning for scheduled actions, more recent power flow analyses, or changed grid configurations, and may potentially provide additional capacity to provide distribution services.
  - Sub Use Case C4b: DSO issues a command to set the maximum operational import (load) limit, within the constraints included in the Limited Load Profile. This Sub Use Case is the equivalent to the commanding of generation export limits but applies to load import limits. This limit may reflect the results of planning for contingencies, planning for scheduled actions, more recent power flow analyses, or changed grid configurations, and may potentially provide additional capacity to provide distribution services.
- Use Case C5. Situational Awareness for Distribution Services
  - Sub Use Case C5a: DSO collects data from the grid and DER at the PCC within a day, not necessarily with a communications protocol (e.g. could be collected via an Advanced Metering Infrastructure (AMI) system), in order to capture active power export, import, demand, outages, and other data for future analysis.

- Sub Use Case C5b: DSO collects alarm and event logs from the grid and DER at PCC within an hour, using a communications protocol, to capture data for near-real-time analysis. This analysis may then be used for near-term planning, scheduling updates, or commands.
- Sub Use Case C5c: DSO monitors the grid and DER export, import, frequency, voltage, and other data at PCC within 5 minutes, using a communications protocol, for possible use in near-real-time commands.
- Sub Use Case C5d: DSO monitors data from the grid and the DER at PCC within one second, using a communications protocol, with the capability to issue real-time commands.

C.4 Business Case D: Operational Flexibility through Voltage Support by DER

- Use Case D1. Modify Volt/Var settings
  - Sub Use Case #D1: DSO establishes enhanced volt/var settings and/or issues command to update volt/var settings
- Use Case D2. Modify Volt/Watt settings
  - Sub Use Case #D2: DSO establishes enhanced volt/watt settings and/or issues command to update volt/watt settings

C.5 Business Case E: Operational Flexibility for Electric Vehicles Providing Distribution Services

- Use Case E1: Peak Power Limiting of Electric Vehicles (Planned or Emergency Load Reduction): The DSO determines that thermal overload constraint of specific circuits is required for the near future. Since these circuits contain charging stations for EVs, the DSO issues a Load Import Limit schedule or command, containing the limit of active power import permitted during the constrained times. The charging station management system (CSMS) then determines if the EVs charging during that time would exceed the import limit. If so, it can request any non-EV DER to increase generation to cover the EV loads. If such a DER does not exist or cannot make up the difference, the CSMS reviews any contractual obligations for the EVs (e.g., emergency vehicles could continue rapid charging) or financial constraints (e.g., an EV owner requests rapid charging), and then determines which other EVs would have their rate of charging slowed down.
- Use Case E2: Fast Frequency Response (FFR) for EVs: The CSMS would receive specific settings of the frequency-watt capability for the EVs to respond to frequency changes within less than 2 seconds by decreasing the rate of charging. The CSMS would allocate the proportion of the frequency-watt response to each EV (and its EVSE) currently charging. If a low FFR event is triggered, the EVSEs would decrease the rate of charging of the connected EVs according to this proportion. Although this Use Case is only for decreasing active power of those EVs charging during an FFR event, the same criteria could be used for any V2G EVs that are able to increase active power by discharging.
- Use Case E3: Frequency-Watt (droop) function: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function, SAE J3072 describes the interoperability requirements for EVs and EVSEs to establish the curves and other parameters for the Frequency-Watt (droop) function. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC. Although this Use Case is only for decreasing active power of those EVs charging

during an FFR event, the same criteria could be used for any V2G EVs that are able to increase active power by discharging.

- Use Case E4: Volt-Watt Response by EVs: The CSMS would monitor the voltage at the PCC. If the voltage at the PCC exceeds the established voltage limits, the CSMS would allocate the proportion of the Volt-Watt response to each EV (and its EVSE) currently charging, and the EVSEs would decrease the charging rate of the connected EVs according to this Volt-Watt proportion. Although this Use Case is only for decreasing active power of those EVs charging, the same criteria could be used for any V2G EVs that are able to increase active power by discharging.
- Use Case E5: Ride-Through Frequency Anomalies for EVs: The EVSEs do not stop charging EVs during a Frequency-Ride Through event as per the equivalent parameters for EV charging as for DER generation.
- "Use Case E6: Frequency-Watt for EVs: The CSMS would receive specific settings of the frequency-watt capability for the EVs to respond to high frequency requirements. The CSMS would allocate the proportion of the frequency-watt response to each EV (and its EVSE) currently charging. If the frequency droop function is enabled, the EVSEs would change the rate of charging of the connected EVs according to this proportion. Although this Use Case is only for decreasing active power of those EVs charging, the same criteria could be used for any V2G EVs that are able to increase active power by discharging."
- Use Case E7: Providing Artificial Inertia in Response to Rapid Frequency Changes for EVs: The V2G EV responds to the rate of change of frequency (ROCOF) by changing its active power production (or consumption) to counteract rapid changes (spikes and sags) in frequency. The CSMS would receive specific settings of the frequency-watt capability for the EVs to respond to frequency changes by decreasing the rate of charging. The CSMS would allocate the proportion of the frequency-watt response to each EV (and its EVSE) currently charging. If a rapid frequency change (spike or dip) event occurs, the EVSEs would decrease the rate of charging of the connected EVs according to this proportion. Although this Use Case is only for decreasing active power of those EVs charging, the same criteria could be used for any V2G EVs that are able to increase active power by discharging.
- Use Case E8: Coordinated Charge/ Discharge of EVs to Ensure Desired State of Charge is Reached at the Requested Time: The CSMS receives information from the EV’s owner that informs the CSMS the time by when the EV is required to reach a specified state of charge. The CSMS then takes this information into account as it determines when and how fast to charge the EV. Considerations include not only the current, on-peak/off-peak, and forecast price of energy, but also any demand charges, load import limits, use of the EV to provide other ancillary services, etc.
- Use Case E9: Permission for a V2G-capable EV to Discharge: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function (Enter Service), SAE J3072 describes the interoperability requirements for EVs and EVSEs for permission to discharge. The functions required include the IEEE Std 1547 Permission to Enter Service function and the Set Active Power function. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC.
- Use Case E10: Set Constant Power Factor: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function, SAE J3072 describes the interoperability requirements for EVs and EVSEs to set constant power factor. The requirements necessitate the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every

EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation, has not been defined, but is being addressed by UL 1741 SC.

- Use Case E11: Volt-Var function: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function, SAE J3072 describes the interoperability requirements for EVs and EVSEs to establish the curves and other parameters for the Volt-Var function. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC.
- Use Case E12: Watt-Var function: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function, SAE J3072 describes the interoperability requirements for EVs and EVSEs to establish the curves and other parameters for the Watt-Var function. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC.
- Use Case E13: Volt-Watt function: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function, SAE J3072 describes the interoperability requirements for EVs and EVSEs to establish the curves and other parameters for the Volt-Watt function. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC.
- Use Case E14: Constant Var function: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function, SAE J3072 describes the interoperability requirements for EVs and EVSEs to establish the parameters for the Constant Var function. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC.
- Use Case E15: Limit Active Power Export function: While IEEE Std 1547-2018 and California's Rule 21 Tariff describe the function, SAE J3072 describes the interoperability requirements for EVs and EVSEs to establish the parameters for the Limit Active Power function. The requirements require the interactions between the EV, the EVSE, and an Energy Management System (EMS) to be automated and for that automation to be tested separately for the individual types (EVSEs and EVs), since it would be impossible to require every EV to be tested with every EVSE. How to automate this interaction between different types of equipment, but yet separately test the automation has not been defined, but is being addressed by UL 1741 SC.

C.6 Business Case F: Operational Flexibility in Community Microgrids

- Use Case F1. Energy Arbitrage: "Use Case F1: Energy Arbitrage: by Community Microgrids (acting as VPPs)": Use tariffs and locational marginal pricing information to optimize revenues or minimize costs. Energy arbitrage involves the shifting of energy production from lower price to higher price times, and the corresponding shifting of energy use from higher price to lower priced times. The community microgrid determines which DER systems (including controllable loads) will participate in meeting the active power export and/or import limits at the PCCs, taking into account generation capabilities and forecasts, loads, the charging of energy storage, the charging of electric vehicles, and any other considerations which could affect the export and import of active power at each PCC. DSOs, in collaboration with the microgrid operator, will manage their equipment for safety and reliability purposes.

- Use Case F2. Community Microgrid Islanding, Separation and Reconnection:
  - Sub Use Case F2a: Intentional Islanding of a multi-facility microgrid: The Use Case addresses the process for normal separation, emergency separation, and reconnection of a microgrid as an intentional island, as a community microgrid (not individual facilities). Such a microgrid would have multiple Points of Common Coupling (PCCs) between its resources and the main grid, requiring coordination across facilities to achieve safe and reliable separations and reconnections.
    - Current track of R.19-09-009 is developing the tariffs that set the terms and conditions by which a non-utility community microgrid can access the IOUs distribution grid to develop and deploy such a community microgrid. See also PG&E’s Community Microgrids Enablement Tariff at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-CMET.pdf
  - Sub Use Case F2b: Grid following resources - Change the functional settings of Rule 21 Tariff requirements, including volt-var, volt-watt, and frequency watt (i.e. droop) settings as well as protection settings related to the different fault currents, in order to operate reliably and efficiently as a microgrid, subject to DSO assessments to avoid harming their equipment within the community microgrid.
  - Sub Use Case F2c: Grid forming resources - Develop requirements and standards for grid forming capabilities as islanded microgrids (*see UNIFI Consortium work at https://sites.google.com/view/unifi-consortium/home, with draft specifications for grid forming inverter-based resources at https://drive.google.com/file/d/19YRpERnsssEJ62H_Tb0edtxHrZI37ZkK/view)*
- Use Case F3. Community Microgrid Management for Grid Services
  - "Sub Use Case F3a: Planning and Management of Community Microgrids: planning for and managing microgrids to provide grid services, either to the main grid when connected, or to the microgrid when islanded. The microgrid planning and management addresses the following situations:
    - Operation and protection when grid-connected but acting electrically and/or financially as a microgrid
    - Operation and protection of DSO equipment when islanded
    - Black start as a microgrid
  - Sub Use Case F3b: As a connected community microgrid, provide grid services to the main grid: Coordination across multiple PCCs would be needed to provide grid services to the main grid in a safe, reliable, and efficient manner.
  - Sub Use Case F3c: As an islanded community microgrid, provide balancing grid services to the microgrid while meeting DSO requirements for safe handling of their equipment:
    - Coordination of generation, storage, and load resources to maintain safety, stability, frequency management, voltage management, etc.
    - Development of requirements and standards for grid forming capabilities.
    - The balancing of grid services, coordination of resources, maintaining of frequency and voltage would not be done by the DSO (unless it was a DSO microgrid) and thus might not be directly within the CPUC’s jurisdiction.
    - However, the DSO can, and will, impose the same requirements on the community microgrid in island mode as the CPUC imposes on the DSO during normal conditions, so CPUC jurisdiction is indirectly applied. For example, if Rule 2 quality of service requirements are not being met,

then the DSO may terminate the island and the loads within the microgrid boundary would be in outage.

  – Sub Use Case F3d: Provide black start capabilities: As an islanded community microgrid, permit the coordination by a balancing authority to reconnect the microgrid to a small portion of the main grid that is still without power.

- Use Case F4. Community Microgrids as Backup Power or Off-Grid Power: Ability to provide power automatically to local loads after an outage or when these loads are not connected to the grid. In common configurations, backup power might consist of an Uninterruptible Power System (UPS) plus diesel generator. In more modern configurations, backup power might consist of PV plus storage systems or even electric vehicles (V2H).

C.7 Business Case G: Operational Flexibility for DER Providing ISO Grid Services

- Use Case G1: Fast Frequency Response (FFR): Definition in IEEE 2800: Active power injected to the grid in response to changes in measured or observed frequency during the arresting phase of a frequency excursion event to improve the frequency nadir (the minimum value of frequency reached during the frequency disturbance) or initial rate-of-change of frequency. Specific settings of the frequency-watt capability to respond to frequency changes very rapidly by increasing or decreasing active power. Detailed performance requirements are defined in IEEE 2800-2022. This autonomous DER capability requires specific settings of the Frequency-Watt function (currently only having Rule 21 Tariff settings for the Droop capability) to meet these more extensive responses. When the transmission and distribution system frequency is outside of a pre-defined frequency deadband range, DERs inject or absorb active power to help push system frequency back within the frequency deadband. Fast Frequency Response (FFR) systems respond to changes in frequency autonomously in a time frame less that one second. The Generating Facilities determine which DER units (Smart Inverters) will participate in meeting the FFR requirements.

- Use Case G2: Synthetic or Artificial Inertia Frequency-Active Power: The DER responds to the rate of change of frequency (ROCOF) by changing its active power production (or consumption) to counteract rapid changes (spikes and sags) in frequency. Currently, rotating machine generator inertia inhibits changes in system frequency. The frequency droop of their governors helps to stabilize frequency on the system. When there are frequency deviations, due to changes in load or generation, large generators inject or absorb active power, in part drawing on inertia, to provide a corrective force. For inverters, the deadband, slope and response time of frequency droop (aka Freq/Watt) settings serve as a redundant backup to the inertia of large rotating machine generators. As the number of rotating machine generators decreases, frequency stabilization must be provided by DERs and more specifically inverter-based resources (IBRs). DERs compliant to Category III of IEEE Std 1547-2018 are capable of frequency support with response times down to 0.2 seconds. Faster response times can be achieved by programming inverters to react to the Rate of Change of Frequency (ROCOF). A standard does not exist for ROCOF functionality, but inverter design and performance can be validated by Distribution Operators.

  The difference between FFR and artificial inertia is not precisely defined since they both respond very rapidly to changes in frequency. However, artificial inertia mimics the response of rotating masses (rotating generation sources) while FFR may go beyond what rotating masses may provide to respond to emergency levels of frequency deviations. The following description captures these distinctions: The term synthetic inertial response must therefore correspond to the controlled response from a generating unit to mimic the exchange of rotational energy from a synchronous machine with the power system. Any other form of fast controlled response can then be termed as fast frequency response. To clarify, synthetic inertial response is a subset of fast frequency response which contains different responses based on frequency and ROCOF. [https://ietresearch.onlinelibrary.wiley.com/doi/10.1049/iet-rpg.2017.0370]

- Use Case G3: Automatic Generation Control (AGC) (Reg Up / Reg Down, Secondary Frequency Control): The DER responds to raise and lower power level requests from the Balancing Authority (ISO) within 2 to 4 seconds to provide frequency regulation support by changing active power export at the PoC or the PCC. In most cases, the DER is an energy storage system, capable of supporting this function both while generating (discharging) as well as when charging. The AGC function could be separated into Reg Up and Reg Down, in which other types of DER could more easily participate. Although AGC commands are usually directly issued by the ISO, alternatively the DER could use the Frequency-Watt function as a secondary or even default participation in the AGC ancillary service, thus responding to changes in frequency by changes in active power export. This Use Case could be applicable at the PoC of an ESS, but other combinations of DER are also possible, in which the export of active power would be measured at the PCC.
- Use Case G4: Operating Reserve (Spinning Reserve) (Tertiary Frequency Control): The DER provides active power reserve to the grid within a short time (potentially seconds but often minutes) when requested.
- Use Case G5: Dynamic Active Power Smoothing: The DER produces or absorbs active power in order to smooth the changes in the active power level (dW/dt) at the RPA. If multiple DER units are involved, one DER unit might act to smooth the active power output at the PoC of another DER unit. If the RPA is at the PCC, then the result of this Use Case is to smooth both generation export and/or load import.
- Use Case G6: Power Factor Limiting (Correcting): The DER supplies or absorbs Reactive power to hold the power factor at the RPA within the PF limit
- Use Case G7: Scheduling Multiple Functions as Ancillary Services: Set up schedules for combinations of active power and reactive power functions after bidding the functions as ancillary services into the transmission or (eventually) distribution market. These schedules would also ensure the DER has adequate active power and/or reactive power capabilities to meet the contracted ancillary service requirements when they start.
- Use Case G8: Frequency Smoothing: The DER produces or absorbs active power in order to smooth frequency changes at the RPA. (Frequency-watt settings, response to ROCOF changes, longer term surges and sags)
- Use Case G9: Voltage Smoothing: The DER produces or absorbs reactive power and/or active power in order to smooth voltage changes at RPA. (Volt-var, volt-watt settings, voltage spikes and dips, longer term surges and sags, flicker)
- Use Case G10: Generation Smoothing: The consumption and/or production of one generation DER is followed and counteracted by another DER to result in smoother export of generation at the PCC.
- Use Case G11: Generation Following: One DER monitors a second DER and compensates for decreased or increased generation of the second DER in order to maintain a specified active power export or import at the PCC, or within specified high and/or low limits.
- Use Case G12: Load Following: A DER monitors the load and compensates for increased or decreased load in order to maintain a specified active power export or import at the PCC, or within specified high and/or low limits.
- Use Case G13: Peak Power Limiting by limiting the load (e.g., energy storage and/or electric vehicle charging) after it starts to exceed a threshold target power level, either by decreasing load or by increasing

generation. This Use Case is similar to Demand Response, except that it could be contractual rather than just price-based.

- Use Case G14: Load Smoothing: The DER follows and counteracts the load by a percentage at the RPA, after the load starts to exceed a threshold target power level
- Use Case G15: Coordinated Charge/Discharge Management: The DER (including EVs) with storage capability determines when and how fast to produce or consume energy so long as it meets its target state of charge (SoC) obligation by the specified time. This is usually needed when prices for producing or consuming energy vary over time. This is particularly important for electric vehicle charging but is also very useful for PV plus storage systems.
- Use Case G16: Default Settings and Actions if Communications are interrupted: Neither Rule 21 Tariff nor IEEE Std 1547 define what should be done if communications are lost
- Use Case G17: Unintentional Islanding: Process for abnormal separation from the grid during emergencies.
- Use Case G18: Black Start: Ability to start without grid power, and the ability to add significant load in segmented groups
- Use Case G19: Anti-Duck Curve Scheduled Dispatch Use Case: The reshaping of load through scheduled day ahead capacity services, which raises mid-day energy demand and decrease peak by flattening the load shape. See https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.
- Use Case G20: Anti-Duck Curve Dynamic Dispatch Use Case: The dynamic reshaping of load based on real-time grid need for daytime excess energy and evening peak demand needs. See https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.
- Use Case G21: Scheduled Capacity Use Case: The reshaping of peak load through scheduled day ahead capacity service. See https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.
- Use Case G22: Dynamic Demand Response Use Case: The dynamic reshaping of load based on real-time grid need for evening peak demand needs. See https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.
- Use Case G23: Dynamic Shift Shimmy: The dynamic reshaping of load based on real-time grid need for daytime excess energy and afternoon/evening ramp. See https://buildings.lbl.gov/publications/2025-california-demand-response for more details on need and potential.
- Use Case G24 FFR Reliability Service: Battery injection for 30 minutes within 5 cycles of frequency set point or ROCOF trigger

Annex D SIOWG Participant Qualifications

D.1 Business Case Qualifications

The main qualifications revolved around timing issues and technical issues, many of which would require detailed discussions with all the stakeholders. These issues include the Business Case qualifications in Table 22.

Table 22: Business Case Qualifications by Participants

Business Case	Participant	Participant Qualifications
Business Case A	SCE	SCE supports this concept with the following qualifications: • Must have developed, tested, and implemented all the systems (such as ADMS) needed to support DERMS communication, and orchestration of DERS in the grid. • All DERs participating in this type of interconnection must be connected to SCE DERMs and must provide real-time (typically 3-5 second interval) or near real-time (typically 15-minute interval) communication as determined by SCE. • DERs must agree, with no question to DSO, that the DERS will be curtailed down to the agree on limit without advance notice as it will be part of SCE and its systems (DERMS) managing the grid • When required by SCE, due to unanticipated conditions, DERs may be required to disconnect or maintain a fixed limit until SCE has determined that limits may be updated • For operations related to support of the grid (such as capacity), the appropriate PPAs (or, for BTM DERs, customers Tariffs that must first be developed) must first be executed before these services can be provided.

Business Case	Participant	Participant Qualifications
	PG&E	PG&E supports the concept of having interconnection agreements that contain firm limits and non-firm capacity for import/export with the following qualifications: • The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections. • The DSO must have the planning tools available to determine reasonable firm and non-firm limits in advance for inclusion in the interconnection agreements. • All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. • Backend IT systems will need to be updated for changes to the interconnection application system, interconnection agreements, application forms, and studies. • Further definition is required of what is in the main interconnection agreement and what should be in an addendum or in the Distribution Interconnection Handbook (DIH) because each program has its own interconnection agreement (e.g., S-NEM, V-NEM, wholesaler, etc.), and a priority should be made to avoid unnecessarily complicating these agreements where addendums or the DIH may be better suited. • All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO. • The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios. • The DSO does not offer a guarantee for the availability of any non-firm capacity. • Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations. • Not all distribution constraints may be able to be mitigated via a flexible interconnection. • For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

Business Case	Participant	Participant Qualifications
	SDG&E	It is important that there be a clear understanding and use of “non-firm” limits. While there are significant potential benefits from using grid capacity that is available under certain conditions (e.g., when, near real-time, loads are expected to be higher than what was studied in an interconnection study), there may be significant disbenefits if this capacity were awarded to an existing generator on a permanent basis. Doing so could make it more difficult (costly) for new entrants with more efficient generation to interconnect to the grid and would constitute an unacceptable “barrier to entry.” As long as the additional export capacity is treated as “non-firm,” and therefore considered available to new entrants seeking to interconnect their generation, this disbenefit is avoided. This business case will require new planning tools and procedures to evaluate the value proposition in specific cases. It will also require advances in communication infrastructure and related standards to facilitate the interoperability challenges between DSOs and the DER operators. Because of issues of maintaining high overall distribution system reliability and safety to workers and the public, the DSO’s must have final control over the interconnection studies. The modern DER system configuration is increasingly complex, even at residential household level. Customers, and even installers, may have limited or no understanding of how the communication system is configured. For example, for a battery plus storage system, is the system AC or DC coupled? If microinverters are utilized, is there a dedicated port available for communication, and if so, is it a serial or ethernet port? Is the system daisy chained or not? Is the total system output measured or estimated based on the main inverter? Answers to these configuration questions would have significant impact on whether the communication to, and the data access provided by these inverters, is accurate enough to support grid analysis, let alone accepting control/analog commands. The availability of ADMS/DERMS is just one piece of the architecture. More feasibility analysis, design, and configuration and testing would have to occur with support from inverter manufacturers and aggregators to implement the use cases within the business case. Support from DER owners and manufacturers is also essential so that additional validation steps can be built into the interconnection process to ensure the DER system level capability is actually in place and can be relied on for Business Cases A through C.
	CAISO	The ISO supports Business Case A so long as the IOU/DSO Non-Consensus and/or Qualifications are remedied.
	Enphase	In general, it looks very good, and Enphase supports the Business Cases.
	IREC	IREC envisions that close to “real-time” signaling and/or controls will be necessary to fully make use of the available time-varying hosting capacity on the distribution system. This leads to the concept of “flexible interconnection.” Allowing for the use case of “firm export and/or import limits” plus optionally “non-firm export and/or import capacities” would benefit DER deployment and distribution system optimization. These non-firm limits could be authorized by the DSOs (via updated schedules, signals or even commands) when they determine in the near-term that there would not be impacts on the safety and reliability of the grid.

Business Case	Participant	Participant Qualifications
Business Case B	SCE	SCE supports this concept with the following qualifications: • On Table in Section 4.2.3 Strike the "societal Benefit" – See comments • Grid abnormal conditions can have impacts on grid, employee, and public safety and thus existing Tariffs to address grid abnormal conditions should not be negatively impacted but enhanced if necessary. • The capability to efficiently allow lower levels of import or export to address an abnormal condition can only be implemented when SCE has developed, tested, and implemented all the systems (such ADMS) needed to support DERMS communication, and orchestration of DERS in the grid under normal and abnormal conditions. • All DERs participating in this type of interconnection must be connected to SCE DERMs and must provide real-time (typically 3-5 second interval) or near real-time (typically 15-minute interval) communication as may be determined by SCE. • Red line accepted or discussed for alignment.
	PG&E	PG&E supports the concept of a coordinated DER operational response to near real-time or pre-planned abnormal grid conditions with the following qualifications: • This business case should not negatively impact the DSO from performing duties to manage abnormal grid conditions safely and efficiently under existing rules and Tariffs. • The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections. • All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E. • All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO. • The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios. • The DSO does not offer a guarantee for the availability of any non-firm capacity. • Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations. • Not all distribution constraints may be able to be mitigated via a flexible interconnection. • For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

Business Case	Participant	Participant Qualifications
	SDG&E	• SDG&E agrees that implementing the latest capabilities for enhancing information exchange and interoperability between DSOs and DER operators is highly important. It is essential that DSOs be able to address emerging and planned maintenance events through orderly processes, including communications with DER operators. However, in emergency events that require immediate system reconfiguration to avoid equipment and property damage or safety risks, DSOs must be able to disconnect DERs immediately, with after-the-fact notification to DER operators as to triggering event and expected recovery process. As DERMS capabilities are developed, they will need the ability to handle these severe events, and the actions taken in less severe cases. Evolution of suitable communication infrastructure and standards is a prerequisite.
	CAISO	The ISO Supports Business Case B so long as the IOU/DSO Non-Consensus and/or Qualifications are remedied.
	Enphase	In general, it looks very good, and Enphase supports the Business Cases.
	IREC	IREC envisions that close to "real-time" signaling and/or controls will be necessary to fully make use of the available time-varying hosting capacity on the distribution system. This leads to the concept of "flexible interconnection." Allowing for the use case of "firm export and/or import limits" plus optionally "non-firm export and/or import capacities" would benefit DER deployment and distribution system optimization. These non-firm limits could be authorized by the DSOs (via updated schedules, signals or even commands) when they determine in the near-term that there would not be impacts on the safety and reliability of the grid.
Business Case C	SCE	SCE supports this concept with the following qualifications: • Strike section that SCE views as not being "Distribution Service" (namely, benefits to DER owners and society) • SCE does not agree that most of the use cases identified in this section are in fact "Distribution Grid Service". • All non-distribution grid services should be removed from this section. • Distribution grid Services are those services that provide support to the operations of the distribution grid under normal and/or abnormal grid condition likely ties to monetary or equivalent compensation. • The capability to provide Distribution services can only be implemented when SCE has developed, tested, and implemented all the systems (such ADMS) needed to support DERMS communication, and orchestration of the DERs which provide distribution service. This functionality may be provided by other means as determined by SCE. • All DERs participating in the Distribution Service operation must be connected to SCE DERMs and must provide real-time (typically 3-5 second interval) or near real-time (typically 15-minute interval) communication as may be determined by SCE. This functionality may be provided by other means as determined by SCE. • Red line accepted or discussed for alignment.

Business Case	Participant	Participant Qualifications
	PG&E	PG&E supports the concept of DER systems and VPPs providing distribution grid services with the following qualifications: • There should be more clarity in what constitutes a grid service. The “do no harm” DER responses under a flexible interconnection for normal and abnormal conditions are not grid services. Suggest potentially removing grid services from Business Cases A and B, and focus Business Case C on grid services for both normal and abnormal situations. • The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for grid services. • All DERs participating in grid services must be connected to PG&E’s DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E. • All DERs participating in grid services must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO. • Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations. • The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios. • Not all distribution constraints may be able to be mitigated efficiently via distribution services. • Not all customers are suitable for providing distribution services. • For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.
	SDG&E	SDG&E agrees with SCE that the meaning of “distribution system services” should be clarified before finalizing this section. SDG&E will also need to coordinate and reconcile its ADMS/DERMS development with the resulting vision for these services. SDG&E does not believe it is necessarily the case that “all DERs” providing distribution services must be connected to SDG&E’s ADMS/DERMS. There may be arrangements where SDG&E communicates with an aggregator who takes on the contractual responsibility for ensuring the DERs within its aggregation operate in accordance with the instructions that SDG&E’s ADMS/DERMS provides to the aggregator. SDG&E notes that the functionalities desired for specific services may vary as to their placement within specific subsystems, such as ADMS, DERMS, and inverters. The path chosen will depend on the nature of the service, the parties involved, and the choices for equipment and software. At this juncture, there is no universal consensus as to what functions should be included in each of the major subsystems. The rule making will need to keep abreast of the changes occurring in these technologies and the related standards.
	CAISO	The ISO Supports Business Case C so long as the IOU/DSO Non-Consensus and/or Qualifications are remedied.

Business Case	Participant	Participant Qualifications
	Enphase	In general, it looks very good, and Enphase supports the Business Cases.
	IREC	IREC envisions that close to “real-time” signaling and/or controls will be necessary to fully make use of the available time-varying hosting capacity on the distribution system. This leads to the concept of “flexible interconnection.” Allowing for the use case of “firm export and/or import limits” plus optionally “non-firm export and/or import capacities” would benefit DER deployment and distribution system optimization. These non-firm limits could be authorized by the DSOs (via updated schedules, signals or even commands) when they determine in the near-term that there would not be impacts on the safety and reliability of the grid.
Business Case E	SCE	SCE supports this concept; However, SCE does not view as this Business Case E as necessary given that all the functionalities as outlined in Business Case E can be provided using Business cases A, B. and C. Therefore, SCE does not support adding this Business Case.
	PG&E	PG&E views the EV use case as a subset of the existing Business Cases (A, B, C) because the interconnection location (EVSE / ISE) would be studied via the Planning process and therefore it should not require an additional separate business case because the functionalities are similar. If in the future V2G AC does not require some type of EVSE / ISE, this may require additional consideration for determining interconnection rules. However overall, PG&E supports the concept of using EVs/EVSEs as an asset for flexible connections and for distribution grid services within the existing framework of Business Cases A, B, and C.
	SDG&E	SDG&E is adding the distribution capacity necessary to accommodate electric vehicle charging loads. Accordingly, SDG&E does not see the need for the CPUC to address “adding ‘load import limits’” as referenced in Table 11, except, perhaps, in the context of a customer’s voluntary consent to accept such limits in exchange for some benefit (e.g., if accepting such a limit allows the charging load to be connected to the grid earlier than otherwise would be possible).
	CAISO	The ISO Supports Business Case E given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSE’s) along with any export capacity providing grid services to the ISO. In addition, the ISO believes that certain EV value use cases can be achieved through inverter control to achieve ‘grid friendly’ charging and incentivizing EV load management through grid informed rates.
	Enphase	In general, it looks very good, and Enphase supports the Business Cases.
Business Case G	SCE	SCE supports this concept; However, SCE does not view as this working group being the correct venue to address ISO Grid Services. These use cases and services should be led by ISO as part of ISO grid service development process.

Business Case	Participant	Participant Qualifications
	PG&E	PG&E supports this concept, in particular, the management of multiple use applications where assets may be participating in both ISO and DSO related services and flexible connections. However, other than the coordination between the ISO and DSO much of this seems unrelated to DSO activities and this should be deferred to the ISO and ISO related venues for addressing many of the topics presented in this chapter.
	SDG&E	SDG&E agrees with SCE but notes that there needs to be clear processes for managing the interfaces between the transmission and distribution systems when distribution-connected DERs are participating in CAISO markets. This is particularly important during abnormal conditions in the distribution system. The CAISO and other stakeholders have considered these interface issues at length in an earlier working group.
	CAISO	The ISO is in general support of continued collaboration and discussion on Business Case G and related uses cases. DER participation under FERC jurisdiction is evolving with required participation at both federal and state regulatory levels. The ISO will continue to support the development of DER integration including improved visibility for grid reliability, as well as pathways for their participation in wholesale markets providing grid supporting services. Pathways for continued efforts in this area include state level proceedings, collaboration with FERC, and ISO stakeholder initiatives for DER policy development.
	Enphase	Enphase agrees with the growing future need for Fast Frequency Response and synthetic inertia i.e. P as a function of RCOF, P(rcof), as a grid service. That said, we oppose the development of any requirements in advance of a consensus National or International Standard for the function. We believe this will be a critical function in a high DER future but also believe it is essential that it will need to be applied to both DER and controllable loads (smart loads) in order to be effective.

D.2 Use Case Qualifications

Participants also provided qualifications for the Use Cases associated with Business Cases A, B, and C in Table 23.

Table 23: Use Case Qualifications by Participants

Use Case	Participant	Participant Qualifications
Use Case 1	SCE	SCE supports this concept with the following qualifications: • Strike section that SCE views as not being "Distribution Service" (namely, benefits to DER owners and society) • SCE does not agree that most of the use cases identified in this section are in fact "Distribution Grid Service". • All non-distribution grid services should be removed from this section. • Distribution grid Services are those services that provide support to the operations of the distribution grid under normal and/or abnormal grid condition likely ties to monetary or equivalent compensation. • The capability to provide Distribution services can only be implemented when SCE has developed, tested, and implemented all the systems (such ADMS) needed to support DERMS communication, and orchestration of the DERs which provide distribution service. This functionality may be provided by other means as determined by SCE. • All DERs participating in the Distribution Service operation must be connected to SCE DERMs and must provide real-time (typically 3-5 second interval) or near real-time (typically 15-minute interval) communication as may be determined by SCE. This functionality may be provided by other means as determined by SCE. • Red line accepted or discussed for alignment.
	PG&E	PG&E supports the concept of scheduling firm export limits and non-firm export capacity for DERs with the following qualifications: • The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections. • All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E. • All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO. • The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios. • The DSO does not offer a guarantee for the availability of any non-firm capacity. • Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations. • Not all distribution constraints may be able to be mitigated via a flexible interconnection. • For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.

Use Case	Participant	Participant Qualifications
	SDG&E	SDG&E supports this use case with the qualification that the definitions of terms in this report are finalized first. The DSOs should have flexibility in negotiating agreements in specific cases to set limits that are consistent with maintaining system reliability and safety in those specific cases. The limits should not become a one size fits all approach.
	CAISO	The ISO Supports Use Case 1 given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads, and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSEs) along with any export capacity providing grid services to the ISO.
Use Case 2	SCE	SCE supports this concept with the following qualifications: • Red line changes proposed are adopted which clarify that for distribution services (normal, planned, or abnormal conditions) the DSO must have a guarantee of a minimum import. Example, if the grid has capacity needs for 2MW, then the participating DER must at minimum provide 2 MW of capacity otherwise the DSO cannot rely on the DER to meet the capacity need. • There appears to be missing a Business case for “reducing or mitigating” interconnection costs for the benefit of the DER owner/operator. For example, allowing DSO to reduce the output of a DER (per Business Case A) eliminate the need to perform grid upgrades which would have to be paid for by the DER owner/operator. • Red line accepted or discussed for alignment.

Use Case	Participant	Participant Qualifications
	PG&E	PG&E supports the concept of commanded firm export limits and non-firm export capacity for DERs with the following qualifications: • The red line changes are adopted to increase scope of commands included in this use case. • The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections. • All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E. • All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO. • The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios. • Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations. • The DSO does not offer a guarantee for the availability of any non-firm capacity. • Not all distribution constraints may be able to be mitigated via a flexible interconnection. • For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.
	SDG&E	SDG&E supports this use case with the caveat that the DSO have the flexibility in negotiating agreements in specific cases to set limits that are consistent with maintaining system reliability and safety in those specific cases. The limits should not become a one size fits all approach.
	CAISO	The ISO supports Use Case 2 given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads, and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSEs) along with any export capacity providing grid services to the ISO.
Use Case 3	SCE	SCE supports this concept with the following qualifications: • Red line changes proposed are adopted to clarify Use Case A3

Use Case	Participant	Participant Qualifications
	PG&E	PG&E supports the concept of generation export minimum requirements with the following qualifications: • The red line changes are adopted to clarify this use case is only for distribution services and should not be a part of the interconnection agreement or abnormal conditions (outside of a distribution service agreement) • The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections. • All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E. • All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO. • The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios. • The DSO does not offer a guarantee for the availability of any non-firm capacity. • Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations. • Not all distribution constraints may be able to be mitigated via distribution services. • For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.
	SDG&E	SDG&E supports this use case with the caveat that DSOs should have flexibility in negotiating agreements in specific cases to set limits that are consistent with maintaining system reliability and safety in those specific cases. The limits should not become a one size fits all approach.
	CAISO	The ISO supports Use Case 3 given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads, and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSEs) along with any export capacity providing grid services to the ISO.
Use Case 4	SCE	SCE supports this concept with the following qualifications: • Discussion should be had on whether DSO having the ability to reduce the load constitutes a grid services. Perhaps it is via a special rate as opposed to through a PPA. • It may be necessary to introduce a new rule that combines Generation DERs and flexible load DERs. • Red line accepted or discussed for alignment.

Use Case	Participant	Participant Qualifications
	PG&E	PG&E supports the concept of applying firm import limits and non-firm import capacity for DERs with the following qualifications: • The DSO must have the planning tools available to determine reasonable firm and non-firm limits in advance for inclusion in the interconnection agreements. • The DSO must have the operational tools such as ADMS and DERMS to visualize DERs, forecast loading, calculate operational limits, communicate dispatches with DERs, identify and mitigate abnormal conditions, and provide measurement and verification for flexible interconnections. • All DERs participating in this type of interconnection must be connected to PG&E's DERMS and must provide real-time (seconds) or near real-time (typically 15-minute interval) communication as determined by PG&E. This functionality may also be provided by other means as determined by PG&E. • All DERs participating in this type of interconnection must have systems that have been tested and commissioned in accordance with the DSO to adhere to signals sent by the DSO. • The DSO and DERs must agree on failsafe mechanisms and default limits during abnormal conditions in emergency and non-emergency scenarios. • The DSO does not offer a guarantee for the availability of any non-firm capacity. • Timelines for implementing systems like state-estimation are longer than measurement-based solutions that may be adequate for some but not all situations. • Not all distribution constraints may be able to be mitigated via a flexible connection. • For any DER provided grid services, the appropriate PPAs, customer Tariffs, or other agreements (that still need to be developed) must first be executed before these services can be provided.
	SDG&E	Conceptually, limiting or controlling grid withdrawals can provide distribution services. For example, an aggregator could contract with customers with electric vehicles and, for some form of compensation paid to the customers, manage their electric vehicle charging in a manner which allows the utility to cost-effectively defer planned distribution infrastructure. The utility would compensate the aggregator provided the aggregator responds appropriately to the DSO's dispatch instructions. This is the model for the Partnership Pilot. Importantly, this model presumes voluntary participation by customers. SDG&E does not support Use Case 4 to the extent it assumes involuntary participation by customers. Customers should have the freedom to consume, or not consume, based on their personal preferences and economic incentives.
	CAISO	The ISO supports Use Case 4 given that the IOU/DSO Non-Consensus and/or Qualifications are remedied. However, in addition the ISO would need visibility into the impact on forecasted and real-time loads, and Scheduling Coordinators would need to update load information on behalf of the load serving entities (LSEs) along with any export capacity providing grid services to the ISO.

Annex E Overview of DER Functional Capabilities in Rule 21 Tariff and Beyond Rule 21 Tariff

Rule 21 Tariff and IEEE Std 1547 have defined a specific set of functions focused almost entirely on DER generation. However, controllable loads can be important to manage for reliability and safety, and many, such as inverter-based stationary storage and electric vehicles, can provide important grid services even while charging. Table 24 includes a list of both the existing Rule 21 Tariff functions and the many other functions that DER systems are capable of providing. These may or may not need to be regulated by the CPUC since they are often focused on the internal management of DER facilities or on providing revenue for DER owners, but many of these capabilities may also be used for grid support.

Table 24: Overview of DER Functional Capabilities

Source or Type	Function/Capability	Communication Req.	DERMS Functional Req.	Source	Priority
Operational flexibility for Rule 21 Tariff Phase 1 functions	**Anti-Islanding** activated/deactivated	• Power monitoring • Real-time or near-real-time for activating/deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
	Low/High Voltage Ride Through activated/deactivated with default or alternative settings	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
	Low/High Frequency Ride Through activated/deactivated with default or alternative settings	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
	Dynamic Volt/Var activated/deactivated with default or alternative volt/var settings	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
	Ramp Rates activated/deactivated with default or alternative normal settings	• Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
	Fixed Power Factor activated/deactivated at specified static setting or dynamically determined setting	• Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	

Source or Type	Function/Capability	Communication Req.	DERMS Functional Req.	Source	Priority
	Reconnect by "soft-start" activated/deactivated with default or alternative settings	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
	Frequency/Watt (Droop or primary frequency control) activated/deactivated with default or alternative frequency/watt settings	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
	Volt/Watt activated/deactivated with default or alternative volt/watt settings	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
Operational flexibility for Rule 21 Tariff Phase 3 functions	**Limit Active Power** activated/deactivated at specified static setting or dynamically determined setting	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
	Set Active Power activated/deactivated at specified static setting or dynamically determined setting	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F, SIWG 2021	
	Send Schedule to Limit Active Power for daily or weekly active power limits	• Real-time or near-real-time for sending schedule	• Scheduling capability • Send schedule	R1707007 WG3, Annex G	
Operational flexibility by adding IEEE Std 1547 functions	**Constant Reactive Power** activated/ deactivated at specified static setting or dynamically determined setting	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	
	Watt/Var activated/deactivated at specified static setting or dynamically determined settings	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	R1707007 WG3, Annex F	

Source or Type	Function/Capability	Communication Req.	DERMS Functional Req.	Source	Priority
Operational safety and reliability	**Monitor key power system status and measurements in real-time:** monitor critical active power, reactive power, voltage, etc., from key DER installations	• Real-time monitoring	• Monitoring and Control	SIWG 2021	
	Fast Frequency Response (FFR): Specific settings of the frequency-watt capability to respond to frequency changes within less than 2 seconds by increasing or decreasing active power	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	IEEE 2800	
	Operating Reserve (Spinning Reserve) (Tertiary Frequency Control): The DER provides operating reserve	• Real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control		
	Peak Power Limiting by limiting the load after it starts to exceed a threshold target power level, either by decreasing load or by increasing generation	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control	IEC 61850-7-420	
	Unintentional Islanding: Process for abnormal separation from the grid	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating • Protective relaying	• Power Flow assessment • Monitoring and Control	IEEE Std 1547 IEEE 2800	
	Black Start: Ability to start without grid power, and the ability to add significant load in segmented groups	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating • Protective relaying	• Power Flow assessment • Monitoring and Control		
Market Benefits to DSO and DER Owner as Ancillary Services	**Automatic Generation Control (AGC)** (Secondary Frequency Control): The DER responds to raise and lower power level requests to provide frequency regulation support	• Real-time control by Balancing Authority	(Balancing Authority AGC)	FERC 2222	

Source or Type	Function/Capability	Communication Req.	DERMS Functional Req.	Source	Priority
	Synthetic or Artificial Inertia Frequency-Active Power: The DER responds to the rate of change of frequency (ROCOF) by changing its active power production (or consumption) to counteract rapid changes (spikes and sags)	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	(Balancing Authority AGC)	IEEE 2800	
	Dynamic Active Power Smoothing: The DER produces or absorbs active power in order to smooth the changes in the power level at the Referenced POC. Rate of change of power	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control		
	Load Following: The DER counteracts the load by a percentage at the Referenced POC, after it starts to exceed a threshold target power level	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control		
	Generation Following: The consumption and/or production of the DER counteracts generation power at the Referenced POC	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control		
	Power Factor Limiting (Correcting): The DER supplies or absorbs Reactive power to hold the power factor at the Referenced POC within the PF limit	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Power Flow assessment • Monitoring and Control		
	Scheduling Functions and Settings: Set up schedules for each DER after bidding the functions as ancillary services into the transmission or (eventually) distribution market.	• Real-time or near-real-time for sending schedule	• Scheduling capability • Send schedule • Monitoring and Control		

Source or Type	Function/Capability	Communication Req.	DERMS Functional Req.	Source	Priority
Market Benefits to DER Owner (including if DSO)	**Coordinated Charge/Discharge Management:** The DER with storage capability determines when and how fast to produce or consume energy so long as it meets its target state of charge (SoC) obligation by the specified time. This is particularly important for electric vehicle charging but is also very useful for PV plus storage systems.	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating • Protective relaying	• EV Charging Station DERMS • Facility DERMS • DSO DERMS		
	Intentional Islanding: Process for normal separation, emergency separation, and reconnection of microgrids. These microgrids could be individual facilities or could be multiple facilities using Area EPS grid equipment between these facilities.	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating • Protective relaying	• Power Flow assessment • Monitoring and Control		
	Microgrid Management: Planning for and managing islanded microgrids with grid forming and grid following DER	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating • Protective relaying	• Microgrid DERMS		
	Backup Power or Off-Grid Power: Ability to provide power automatically to local loads after an outage or when these loads are not connected to the grid. In common configurations, backup power might consist of an Uninterruptible Power System (UPS) plus diesel generator. In more modern configurations, backup power might consist of PV plus storage systems.	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating • Protective relaying	• Facility DERMS		
	Energy Arbitrage: Use near-real-time pricing information to optimize revenues or minimize costs.	• Power monitoring • Real-time or near-real-time for settings and activating/ deactivating	• Facility DERMS		