Technical Rationale

NERC Project 2022-02 | MOD-032-2, TOP-003-8, and IRO-010-6
August 2025

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. It should be noted that Generator Owner (GO) applicability includes both Category 1 GO and Category 2 GO consistent with proposed revisions to the definitions of those terms developed under Project 2024-01 Rules of Procedure Definitions Alignment.

Additionally, the drafting team (DT) reviewed the dual applicability to Planning Authority (PA) and Planning Coordinator and determined that it was most appropriate to reference both terms in the applicability section until NERC registration criteria are updated to use only a single term. The posted "Appendix 5B: Statement of Compliance Registry Criteria," dated June 27, 2024, still uses both terms and, arguably, the PA term is used more prominently. However, the explanation included in MOD-032-1 refers to synchronization between registration criteria and the NERC functional model which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the DT excluded the explanatory language from MOD-032-2 Applicability Section.

Rationale for Distributed Energy Resource (DER) Definition

The DT has proposed that a definition for DER be added to the *NERC Glossary of Terms used in Reliability Standards* (NERC Glossary of Terms). The approved standard authorization request (SAR) to revise MOD-032, submitted December 2021, noted that "it may be needed (based on the discretion of the DT) to add a definition for 'Distributed Energy Resource (DER)' to the NERC Glossary of Terms" in conjunction with adding DER data to Attachment 1, the main purpose of this SAR.[1] The DT found it necessary to draft a DER definition to clarify the usage of this term within the standard. Further, the DT recognized benefits of a NERC Glossary of Terms definition to bring alignment and consistency of term usage across Reliability Standards. Additionally, the term Inverter-Based Resource (IBR) was recently defined in the NERC Glossary of Terms under Project 2020-06 for a similar reason. Finally, the DT was comprised of team members with adequate experience to propose a definition, including members of the NERC SPIDERWG and IEEE 1547 working group.

The DT proposes to define Distributed Energy Resource (DER) as follows:

"A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system."

[1] SAR title "MOD-032-1 Data for Power System Modeling and Analysis", submitted 12/15/2021. Available at: https://www.nerc.com/pa/Stand/Project202202ModificationstoTPL00151andMOD0321DL/2022-02_MOD-032%20SAR%20SPIDERWG_020122.pdf

In developing this definition, the DT considered various DER definitions utilized in the industry and discussed in the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Terms and Definitions Working Document, including the six other definitions described in Appendix D that were not adopted by SPIDERWG. Through this review, the DT determined each of these seven definitions would benefit from refinement to be most suitable for application in MOD-032 and future reliability standards more broadly. It is expected that most reliability standard revision proposals related to DERs would originate from the SPIDERWG. Thus, the DT's intent was to propose a DER definition that aligned with the SPIDERWG working definition, which explicitly excludes demand response and clarifies what is in scope and out of scope with respect to where a DER is connected, rather than the technology type.

The DT considered adopting a voltage threshold to define distribution. However, industry generally differentiates transmission from distribution based on the functional use of the system rather than technical specifications (e.g., voltage, active power, etc.). Setting aside the Bulk Electric System, that has a NERC definition, defining electric facilities as either transmission or distribution is often based on State law or regulations, ISO/RTO tariff, and/or utility tariffs. There are no conflicts in how applicable entities define distribution and transmission facilities for a given region, even if those definitions vary from region to region. Additionally, the DT considered an active power threshold to define DER and concluded that DER technologies can vary in size, and a threshold might inappropriately exclude technologies that are DER[2]. At the same time, the DT understands that certain applications of DER data, for instance determining when or how a Transmission Planning (TP) or Planning Coordinator (PC) includes DERs into planning processes (e.g., TPL-001), may include active power or other TP or PC defined thresholds.

The DT considered defining DER based on the resource not being connected to the Bulk Power System (BPS), similar to the IEEE 1547-2018 definition that uses "not directly connected to the BPS" to describe DERs. However, the NERC Glossary of Terms definition of BPS does not provide specificity that would enhance a definition of DER beyond an undefined term that is generally used in industry. The phrase "distribution system" was selected to expressly describe the type of electric facilities that would cause a resource to be defined as a DER, if interconnected to those facilities.

The DT recognizes that "distribution system" is not defined in the NERC Glossary of Terms and that the SPIDERWG proposed a definition.[3] The DT reviewed the SPIDERWG definition and concluded that it would not clarify the term DER. The SPIDERWG use of the term "transmission-distribution" interface within a definition of "distribution system" could be considered a circular reference that causes ambiguity. The DT is not proposing a definition for distribution system given any proposed definition could be of limited benefit for clarifying the proposed definition for DER.

Below is a summary of the rationale for the DT departing from each of the seven definitions when proposing a new DER definition.

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[2] NERC has published a study recommending that a zero MVA threshold be used when collecting DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

[3] SPIDERWG definition of "distribution system": The electrical facilities that are located behind a transmission-distribution transformer that serves multiple end-use customers. https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

SPIDERWG definition

After considering the SPIDERWG definition, the DT determined it provided a useful foundation but needed refinement to be suitable for the intended use. Specifically, the SPIDERWG term included transient types of DER power beyond generation and storage, and it included sources of back-up power that would have no potential grid impacts.

The DT chose to refer to a generator or storage technology specifically, rather than use the SPIDERWG language of “source”, to exclude devices or resources that only transiently inject real power (e.g., regenerative elevators, transition switches, etc.). A DER can use various technologies including synchronous machines, induction machines, and power inverters/converters (i.e., IBR). Different types of DERs can utilize a wide range of energy sources including, but not limited to, natural gas, diesel, hydro, storage, wind, and solar. Additionally, the DT intention was to ensure that the scope included facilities “connected behind the meter of an end use customer” that may export Real Power to the power system or offset Real Power load (e.g., residential solar or commercial rooftop solar). This would exclude technologies such as charging-only electric vehicle (EV) installations and controllable load. While not finalized, it is the drafting team’s understanding that this determination is consistent with recent proceeding from the IEEE 1547 revision Working Group. To exclude transmission connected load customers that have onsite generation or storage resources, the DER definition clarifies that the behind-the-meter customer “is supplied from a distribution system”.

The DT included the language "in non-isolated parallel operation with the Bulk-Power System" to indicate that a distributed energy resource with potential BPS reliability impacts is only one that has electrical connectivity to the BPS. A resource that is only operated in islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BPS and, therefore, is not of interest from a BPS-reliability perspective. The DT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry. The DT intentionally avoided the term “directly connected” to differentiate electrical connectivity from an electrical connection point. The phrase “connected to the distribution system” speaks to electrical connectivity and the subsequent phrase “including one connected behind the meter of an end use customer” clarifies this connectivity includes a resource directly connected to a customer system (i.e., behind the meter).

IEEE 1547-2018

The DT reviewed the IEEE 1547-2018 definition and found that it contained elements that could supplement the SPIDERWG definition to address the issues identified above. The DT incorporated the explicit reference to generation and storage aspect of the IEEE definition. Further, the IEEE concept of “capable of exporting active power to an EPS” informed the need for capturing non-isolated, long-term paralleling and the sourcing of Real Power (i.e., active power) within the DT definition.

At the same time, the DT did not view the IEEE definition as suitable for the DT’s intended use as written. The IEEE term qualifies the DER connection point as “not directly connected to a bulk power system” which the DT viewed as potentially ambiguous. Instead, the DT opted for the “connected to a distribution system” language to point to the electric system location, and how facilities at that location are classified, as a key concept in differentiating DERs from other generators and energy storage technology. The DT considered if it was necessary to define "supplemental DER devices" as part of the DER definition and determined this nuance is not needed for a NERC Glossary of Terms DER definition.

Federal Energy Regulatory Commission (FERC) Energy Primer
The DT identified the FERC Energy Primer definition as being inclusive of load resources (e.g., energy efficiency, demand response) which is not aligned with the SPIDERWG definition. Given the reliability use cases, the DT and SPIDERWG definitions target sources of electric power, with the DT narrowing this definition to be only sources "capable of providing Real Rower." After considering the FERC definition, the DT determined it was not suitable for the intended use.

National Association of Regulatory Utility Commissions (NARUC)
NARUC's definition is also inclusive of load resources (e.g., energy efficiency, demand response) and therefore, the DT concluded it is too broad.

NERC DERTF
The NERC DERTF definition uses the language "resource on the distribution system that produces electricity" which appears to exclude distributed energy storage, a technology necessary for inclusion in the DT definition. Further, the NERC DERTF definition defines DER as anything "not otherwise included in the formal NERC definition of the Bulk Electric System" which the DT views as overly broad.

California Public Utilities Commission (CPUC)
The CPUC definition appears to be based on California legislation and includes energy efficiency, EVs, demand response, renewable generation resources, and energy storage. As is the case for FERC and NARUC definitions above, the inclusion of load resources is overly broad for the NERC Glossary of Terms.

New York Independent System Operator (NYISO)
The NYISO definition only considers market-qualifying resources as DER. This definition's exclusion of a large portion of DER (i.e., retail participation) is too narrow for the reliability planning needs identified by the SPIDERWG DER Modeling Study.

Figure 1 below provides a graphic illustration of the DER definition and the intended scope of facilities that would fall under the proposed definition. Figure 2 below shows that the proposed DER and IBR definitions are compatible, but distinct. Some resources may be classified as a DER, but not an IBR; some resources may be classified as an IBR, but not a DER; some resources may be classified as both a DER and an IBR. This relationship between the definitions and the existence of non-IBR storage solutions informed the phrasing of "generator and energy storage technology" to ensure all generators and all storage devices are included, even if they do not meet the definition of IBR. Note that in Figure 2, "distribution-connected" is shorthand for connected to the distribution system and "bulk system-connected" refers to resources connected to the transmission system.

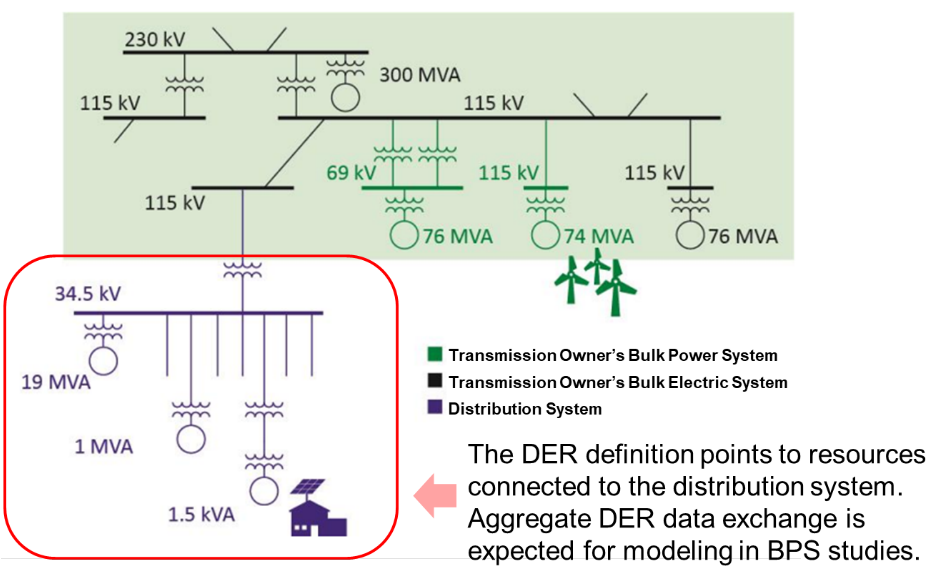

Figure 1: DER Definition Illustration

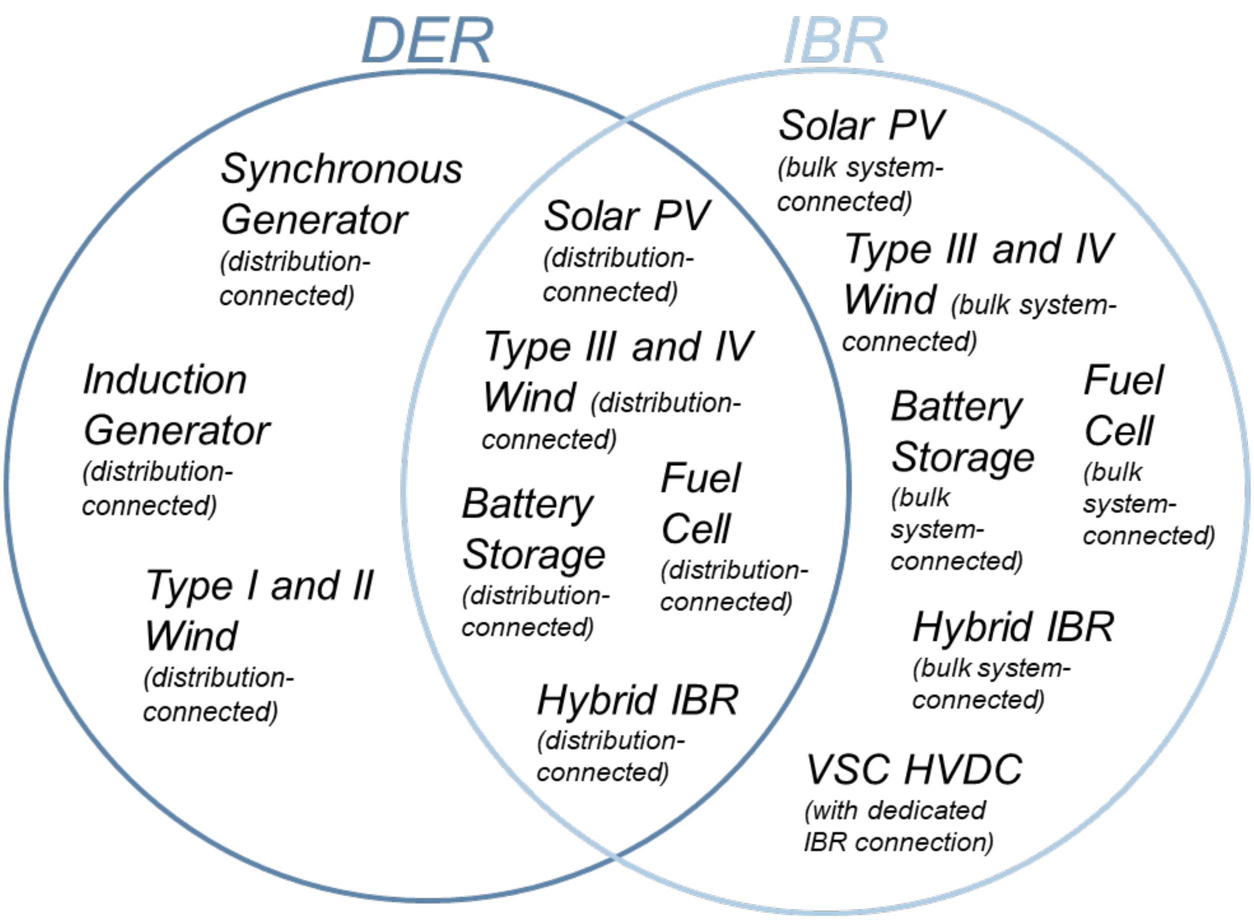

Figure 2: DER and IBR Definition Compatibility

Rationale for Modifications to Requirement R1

Requirement R1, Part 1.1 was modified to require that the PC and TP data requirements and reporting procedures include the responsible entity for data items listed in Attachment 1. To be clear, the "entity" to be identified would be the entity type or category (i.e., Transmission Owner), not specific companies for each data item. This modification aligns with changes made to the introductory paragraph in Attachment 1 clarifying that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The intention of this addition is not to create an administrative requirement for the PC and TP to maintain separate lists identifying entity obligations, but to reinforce PC/TP authority to request data from appropriate entities, thereby creating obligations for those entities to provide the requested data. In most cases, it is expected that data requirements and reporting procedures would inherently identify the entities required to provide data. Further, this modification is intended to give the PC/TP flexibility to identify (and specify within their data requirements and reporting procedures) the best source for necessary data, even if that source is not a NERC functional entity. However, only NERC functional entities are subject to mandatory compliance with NERC Reliability Standards, so the PC/TP is unlikely to assign other entities without a local authority to create data obligations outside of NERC enforcement. Such flexibility could allow the TP or PC to directly estimate data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes and aggregated DERs connected to unregistered Distribution Providers based on any information received in accordance with their data requirements and reporting procedures. As an example, data received from DPs in the area that can be assumed to have similar DER adoption profiles. FERC Order 901 uses the phrase "unregistered IBR" but given this is an undefined term and the drafting team received opposition to explaining that term in a footnote, the phrase was replaced in the standard with "an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes." This is the intent of all further references to "unregistered IBR" in this technical rationale.

FERC Order 901 directs NERC to develop reliability standards that require "the use of approved industry generic library IBR models".[4] However, pre-defining a limited set of models (i.e., a library of models) that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To align with industry practices while addressing the directives of the FERC Order, the DT incorporated elements from the NERC Dynamic Modeling Recommendations into Requirement R1, Part 1.4, rather than defining an inclusive model library. The DT supports the approach and views it as aligned with the FERC Order directives while addressing the practical limitations raised by industry at the January 15-16 and June 3-5 NERC Industry Engagement Workshops.[5][6] For instance, Order 901 P125 requires "the sole use of nation-wide approved component generic library models" whereas workshop participants raised issues surrounding timelines for approving library models that reflect new IBR products, the accuracy of library models for certain products, timelines associated with updating library models, and referencing a document outside of the standard that could be changed by a process also outside the standard, among other issues.

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[4] FERC Order 901 at Paragraph 122.

[5] NERC_Industry_Engagement_Workshop–Reliable_IBR_Integration_and_Milestone_3_of_FERC_Order_901_Agenda

[6] Milestone 3 of FERC Order 901 NERC Industry Engagement Workshop June 3-4 PowerPoint

To address these concerns, Requirement R1, Part 1.4 includes requirements for the PC/TP to specify submission of standard library dynamic models, user-defined models, or both. The phrase user-defined models should be considered interchangeable with user-written models, equipment-specific models, and other such terms. The phrase “user-defined models” was used in MOD-032-2 based on language in FERC Order 901.[7] Allowing the specification of standard library models incorporated within modeling software is responsive to FERC concerns about usability and allows PCs to maintain current requirements for generic models that may be necessary for the creation of large Interconnection-wide base cases. Allowing the specification of user-defined models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. The DT also explicitly ensured PC/TP authority to require submission of both model types, if deemed necessary. Requirement R1, Part 1.4.2 is responsive to FERC concerns about model usability and non-convergence by requiring PCs and TPs that accept user-defined models to specify usability requirements and require appropriate model documentation and instructions.

Rationale for Modifications to Requirement R2

Requirement R2 was modified to require estimation of modeling data if the Responsible entity (typically the Transmission Owner or Distribution Provider) is unable to gather required data. FERC Order 901 requires the provision of data related to unregistered-IBR and IBR-DER that in the aggregate have a material impact on the BPS.[8] If the data is estimated, Requirement R2 Part 2.1 also requires the entity to provide an explanation of the limitations of the estimated data and the method used for estimation in line with the Order 901 directives.[9] The requirement language intentionally uses the phrase “unable to gather” to mirror the FERC Order 901 language. Limitations of the estimated data is intended to capture both limitations of the availability of data (including instances where there are legal or contractual prohibitions on requesting certain data, no mechanism to enforce collection, or incomplete records of what is connected) and limitations of any data provided (including partially missing or suspect data).

The exact method used for estimation is intentionally left open given the varying levels of data available across the ERO footprint. A few possible examples include:

- A full list of DERs broken down by resource type with limited fields missing and assumed based on other characteristics.
- Real Power capability by resource type with approximate percentage of the resource compliance with various IEEE 1547 versions used for dynamic performance assumptions (known or assumed based on installation date).
- Count of resources by resource type with average size used to estimate Real Power capability.
- Derive values for unregistered DPs based on average of registered DPs in the area (scaled based on total system size).
- Solar capability estimated based on satellite imagery of rooftops.

[7] FERC Order 901 at P124

[8] FERC Order 901 at P104 and P105

[9] FERC Order 901 P104: “if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation.”

- Assumptions of regional/national average IBR-DER penetration levels.

Additional guidance for DER estimation can be found in NERC SPIDERWG Reliability Guidelines on the topic.[10]

The DT views the introduction of this estimation provision as alleviating previously expressed compliance obligation concerns around challenges in collecting data for DERs connected to unregistered entities. Further, the addition of compliance abeyance language for the estimation process provides entities the opportunity to hone their estimation process without risk of penalty (provided they proceed in good faith). The approach directed by FERC is flexible as to whether the underlying unregistered IBR and DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data availability or sufficiency issues, among other factors, may lead to the DP and TO applying a combination of approaches to source the data. The PC and TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

While the FERC Order 901 directives only addressed IBR-DER, meaning that DER technologies based on induction generators or synchronous generators are not explicitly addressed, Project 2022-02 is also assigned a SAR that requires DERs to be addressed in MOD-032 more generally, and the inclusion of all DERs in this revision of the standard removes the need for a second modification under this project. The DT found it practical to have a consistent estimation framework applicable for all DER technologies when DER data cannot be gathered. Therefore, Requirement R2 was intentionally written to have requirements for estimating DER data regardless of the technology type, when an applicable entity is unable to gather the data. The approach FERC directed NERC to use forms the basis for this uniform approach.

Given the challenges with collecting complete and accurate DER data, the DT would still recommend that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would delay the project beyond the FERC Order 901 Milestone 3 timeline. The DT considered adding "UFLS-Only Distribution Provider" to MOD-032-2 applicability to reduce (but not necessarily eliminate) the potential gaps associated with DER connected to unregistered entities with no compliance obligation. However, the UFLS-Only Distribution Provider can only be obligated to provide data directly associated with UFLS programs (essentially the data identified in Attachment 1 Dynamics Column 10b). Provision of such data in the absence of the other DER data identified in Attachment 1 would not be particularly useful for planners.

Requirement R2, Part 2.2 was added to confirm the relationship and consistency between MOD-026 and MOD-032 indicated in FERC Order 901 Paragraph 143[11]. The DT believes that the intent of FERC Order 901

[10] Reliability Guidelines, Security Guidelines, Technical Reference Documents, and White Papers

[11] FERC Order 901 P143: ""Regarding EPRI's recommendation to require appropriately parameterized plant models, we agree that the model verification process of an IBR model should include steps to ensure that responsible entities provide both verified and appropriately parameterized models. Additionally, we agree with IRC's recommendation that the plant model verification process should include requirements for equipment to be represented as installed in the field. While we decline to include this level of detail in the directive to NERC, we nonetheless direct NERC to establish a standard uniform model verification process. A uniform model verification process will

is to ensure that accurate (validated and verified) models are collected under MOD-032. However, facility models submitted under MOD-032 are often submitted before physical validation can be completed (e.g., for planned facilities). Part 2.2 requires the model submitted by the functional entity be the model that was verified and validated (and accepted by the TP) in accordance with MOD-026, if available.

Requirement R2, Part 2.3 introduces a reference to the Unacceptable Models List (UML) maintained by the ERO. The DT concluded that it would be most appropriate for NERC to maintain the UML as a separate document that could be updated more quickly and frequently than the standard development process. However, any changes to the process for modifying the UML, that is incorporated into MOD-032-2 as a supporting document, would need to be approved through the standard development process.

It is also recognized that models on the UML may be the best available for some generators, particularly for some synchronous generators and for units manufactured by companies that are no longer in business. Part 2.3 allows for the submission of such a model if accompanied by a technical rationale justifying its use. The requirement does not intend any specific level of scrutiny for this rationale, but it also does not prevent the PC or TP from identifying technical concerns with the model or the rationale per Requirement R3. This rationale could include notation of prior usage for synchronous generation as well as models that have been recently added to the UML without time to procure an updated model prior to reporting. A MOD-032 supporting document defines the process for modifying the UML as a sufficient safeguard to prevent arbitrary or unvetted modifications being made to the UML.

Rationale for Modifications to Requirement R3

Requirement R3, Part 3.1 was modified to include the phrase "that is responsive to the technical concern". The ultimate intent of R3 is to resolve technical concerns that are identified by the PC or TP. However, model providers may not always be able to know that their update or explanation will resolve the planner's technical concern. The intent of this addition is to convey that the model provider's obligation does not simply end with providing a response, but further information exchanges between the planner and model provider may be necessary to resolve the technical concern.

Rationale for Modifications to Attachment 1

Data items specific to IBRs and DERs were added to MOD-032-2 Attachment 1: Data Reporting Requirements.

The DT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with items are only presented in one column (i.e., some sub-bullets are only listed in the "steady state" column even though the data is also relevant to "dynamics" and/or "short circuit"). This long-standing approach was made explicit in footnote 1 of the MOD-032-2 Reliability Standard.

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ensure that all entities use the same set of minimum requirements to verify that all generation resource (i.e., synchronous and non-synchronous) models are complete and that the models accurately represent the dynamic behavior of all generation resources at a sufficient level of fidelity for Bulk-Power System planners and operators to perform valid interconnection-wide, planning, and operational studies. Therefore, we direct NERC to define the model verification process and to require consistency among the model verification processes for existing Reliability Standards (e.g., FAC-002, MOD-026, and MOD-027) and any new or modified Reliability Standards."

The format of Attachment 1 was modified to minimize replicating footnotes applicable to multiple items by adding a new footnotes section (Attachment 1 Data Reporting Requirements Footnotes) to the document. Along with the reformatting, language was added to the introductory paragraph to clarify that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1.

Modifications for IBR

To incorporate IBR within Attachment 1, "and storage units" was added to generating units in the steady-state column under item 3. "Generating units" already incorporates IBR generators such as solar and wind. Storage is typically not classified as a generation resource because it has no primary energy source and consumes more energy than it injects when considering losses. Therefore, the DT found it necessary to include storage explicitly. Footnote 4, associated with "Generating units and storage", was also updated to explicitly identify IBR as an applicable technology for the item and remove pumped storage now that storage is explicitly identified.

The dynamics column was updated to replace "photovoltaic systems" (PV) with "Inverter-Based Resources" under item 7. IBR encompasses PV, resulting in PV technology still being included under this new item.

The three following sub-items were added to dynamics item 7 based on specific language from the FERC Order 901, Paragraph 141.[12]

- IBR capabilities related to momentary cessation,
- Tripping, and
- Ride-through

"Frequency control" was added as a sub-item because frequency response of IBR is important for studying system reliability. For instance, a 2024 NERC Lessons Learned report shows how IBR frequency response can affect system performance.[13] Frequency control encompasses primary frequency response, fast frequency response (e.g., IEEE 2800-2022, Subclause 6.2), and potentially other frequency responsive controls (e.g., "grid-forming" virtual synchronous machine controls).

"Voltage control" was added to encompass reactive power and voltage control that may affect the dynamic or steady state performance of the plant. NERC's Level 3 Alert on Inverter-Based Resource Performance and Modeling, issued May 2025, contains Essential Action #1 indicating the importance of voltage control performance for normal and post-disturbance operations.[14]

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[12] FERC Order 901, P141 states that IBR and IBR-DER data must include "momentary cessation and/or tripping, and all ride through behavior."
[13] NERC, Lessons learned, Incorrect IBR Primary Frequency Response Logic Caused Negative ACE. Available at: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20240501_Incorrect_IBR_Primary_Frequency_Response_Logic_Caused_Negative_ACE.pdf
[14] NERC, IBR Performance and Modeling, Level 3 Alert. May 2025. Available at: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/Level%203%20Alert%20Essential%20Actions%20IBR%20Performance%20and%20Modeling.pdf

In order to clarify dynamics item 6, "wind plant model", to not overlap with the new IBR item 7, type 1 and type 2 wind turbines are specifically called out under item 6. These technologies are not IBR.

Footnote 5 indicates that the PC/TP data requirements and reporting procedures need to account for IBRs that are not DERs and do not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes. It also indicates that the TO is typically responsible for such data.

Modifications for DERs

Item 9, "Aggregate Distributed Energy Resource (DER) data" was added to the steady state column with location, real power capability, and DER type (solar, battery, diesel generator, etc.) specified as required subitems. The DT selected these subitems as the minimum information needed to use data and make assumptions for power system modeling and analysis; the PC/TP have the authority to request additional data items as deemed necessary.

The intent is that relevant DER data be available and represented in models of the interconnected transmission system consistent with the NERC approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. Specific data items listed for DER reflect the minimum information needed to reasonably represent DER in transmission system models. "Aggregate DER" is specified in item 9 to indicate aggregate DER data, rather than individual DER facilities, would be represented in most PC/TP study models.[15] The word "aggregate" was specifically added to Attachment 1 to clarify this point based on industry comments and to align with FERC Order 901. However, Requirement R1 provides the PC and TP great flexibility in developing data requirements and reporting procedures that align with local practices and needs, in addition to the required items listed in the Requirement R1 Parts. Given industry comments on DER data availability, and FERC Order 901 directives, a process is needed for estimating DER data when an entity is unable to gather it. The process for estimating those values is referenced in Requirement R2, Part 2.1.

Footnote 3, associated with "aggregate demand", was modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DERs is not consistent with a modeling framework that explicitly represents DERs.

Dynamics item 5, previously "demand", was updated to be "aggregate demand" to be consistent with the steady state column and general industry practices of modeling load dynamics for aggregate demand (e.g., composite load model).

Dynamics item 10 was updated to include "Aggregate Distributed Energy Resource (DER) data" along with the subitems: "parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control"; and "indication whether DERs are subject to tripping in conjunction with UFLS or UVLS".

[15] In certain circumstances (e.g., a very large DER), a TP or PC may decide to represent the individual DER. However, the DT anticipates most DER information will be aggregated based on PC and TP planning practices.

Momentary cessation, tripping, and ride-through of aggregate DERs is needed for dynamics studies. For instance, NERC's Lessons Learned, LL20220401 "Distributed Energy Resource Performance Characteristics during a Disturbance" provided information following the loss of 300 MW of DERs following a system fault. The report indicated that:

> "There is a need to understand how distribution system connected generation, and loads will behave and how they can accurately be modeled under expected system contingencies. Entities should know the behavioral characteristics of DER inverters on their system (both new and old) as well as their number, capabilities, and locations and then report that information to their Balancing Authorities and Reliability Coordinators so their models can be accurate".

Voltage control of DERs can alter the exchange of reactive power between distribution and transmission systems and may affect the results of reliability studies. Examples are described in the approved Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources.

Frequency control must be accounted for because DER interconnection under different standards (e.g., IEEE 1547-2003 versus IEEE 1547-2018) have different frequency response characteristics that may affect dynamics study results. Frequency control in this case typically refers to the frequency-droop characteristic outlined in IEEE 1547-2018, Subclause 6.5.2.7 and adopted in many jurisdictions. However, should other DER frequency controls become common in industry, those would also fall under this category.

As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is vital for designing and evaluating UFLS programs. Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact to Under Voltage Load Shedding Program Design. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DERs subject to each UVLS/UFLS tripping stage should be identified.

In response to comments, the DT added Footnote 7, which explicitly confirms the PC/TPs discretion to specify aggregation thresholds below which they do not consider DER data necessary to collect. Based on the 0 MVA threshold recommendation noted previously, this threshold should only be established following consideration of that DER Modeling Study Report[16].

Inferring DER Capabilities

Item 10 in the dynamics column indicates that aggregate DER dynamics modeling data may need to be inferred due to data availability and practical limitations. As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DERs may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. For example, in a certain jurisdiction DERs installed after a specified date may be required to have a certain ride-through characteristic. Thus, the appropriate Ride-through characteristic representation for DERs in that area could be inferred by the in-service date of the DERs. However, the PC/TP modeling data requirements and

[16] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

reporting procedures may require the provision of alternative information to achieve the same purpose. PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed (and specified in the PC/TP requirements) to make inferences regarding the overall aggregate DER response characteristics.

Entity responsibilities and coordination

Footnote 6 indicates that the PC/TP data requirements and reporting procedures need to account for situations where DERs are connected to the system of an unregistered DP. When a DER is connected through a registered DP (directly connected to that DP, connected to an unregistered DP that is connected to that DP, or behind the meter of an end-use customer of either) that DP is the typical responsible entity for collecting and providing the DER data. Further, the TO would be the typical responsible entity if there is no system owned by a registered DP between the DER connection point and TO system. This clarification is necessary to reduce the possibility of DERs on the system being unaccounted for by any entity. The DT was responsible for the FERC Order 901 directive requiring an entity to be identified when DERs had no registered DP. It is possible that a company that is a registered Generator Owner may also own resources that do not meet the criteria for registration. That would not change the responsible entity identified per R1, though the owner is encouraged to provide all relevant data to that responsible entity. This point applies broadly, where nothing in the standard is intended to preclude coordination among entities to make sure the responsible entity has the best available information to provide.

The PC/TP may have access to sufficient data for modeling certain DERs through alternative means (e.g., direct registration of DERs or DER aggregators in certain markets). In such cases, the DP (or TO) should not be obligated to provide duplicate DER modeling data, but care will be needed to ensure DERs are not double counted. The PC/TP modeling data requirements and reporting procedures should clearly identify if there are certain classifications of DERs that are excluded from the DP/TO obligation for providing DER modeling data. This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its PC and TP under Requirement R1.

It should be noted that the MOD-032-2 modifications do not change the classification of unregistered IBRs or DERs to become BES facilities subject to NERC reliability standards. Instead, the modifications place a compliance obligation on NERC registered entities (typically DPs or TOs if identified as the responsible entity by the PC/TP) to provide basic information about unregistered IBRs or DERs that are connected to their systems so they can be properly represented in Interconnection-wide cases. There are already existing requirements for such entities to provide information about load connected to their systems. Like load, unregistered IBRs and DERs are not generally considered to be BES facilities. However, BES reliability assessments require an accurate representation of aggregate load, unregistered IBR, and aggregate DER behavior. The modifications proposed in MOD-032-2 are intended to ensure sufficient data is available to the PC/TP so that appropriate unregistered IBR and DER representations can be included in their BES reliability assessments as required by FERC Order 901 and system planning needs.

IRO-010-6 – Reliability Coordinator Data Specification and Collection; and TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

The DT reviewed existing IRO-010 and TOP-003 versions and found that both standards had broad requirements language that encompassed generation and storage resources, including IBR. Nevertheless, to ensure no ambiguity that FERC Order 901 requirements are met, the DT included explicit references to IBR-specific data and parameters and pointed to the uniform framework through an alignment between planning and operations models.

Rationale for Modifications to add "IBR-specific data and parameters"

The phrase "IBR-specific data and parameters" was added to the following requirements:

- IRO-010-6 Requirement R1, Part 1.1
- TOP-003-8 Requirement R1, Part 1.1
- TOP-003-8 Requirement R2, Part 2.1

These modifications were made in response to FERC Order 901 directives related to the inclusion of IBRs in operations models.[17] The phrase "IBR-specific data and parameters" in the revised IRO-010-06 and TOP-003-8 is intended to reflect what FERC describes in the order as "IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions".

Rationale for Modifications to add reference to MOD-032

"Requirements for model submissions to be consistent with the model submitted for planning purposes, as applicable" was added to the following requirements:

- IRO-010-6 Requirement R1, Part 1.5.3
- TOP-003-8 Requirement R1, Part 1.5.3
- TOP-003-8 Requirement R2, Part 2.5.3

These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. Models submitted for planning purposes are typically in accordance with MOD-032, though additional standards or regional requirements may apply. Simulation time constraints in an online operations environment may warrant a reduced model structure complexity; such models may differ from, but should still be consistent with, more complex modeling that is submitted under MOD-032. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon. For example, consistent models would not be appropriate if an update was made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation.

[17] FERC Order 901 Paragraph 122 and Paragraph 161