Order 2222 Design Discussion

PJM Staff

DIRS
August 2021

- Proposal updates addressing Order 2222 Directives and Order 2222A and Order 2222B clarifications and updates.
- PJM presentations and overviews linked here:
  - Order 2222
  - Order 2222A
  - Order 2222B

Order 2222 Compliance Directives

- Allow DER aggregations to participate directly in RTO/ISO markets, and establish DER aggregators as a type of market participant (130);
- Allow DER aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations (130);
- Establish a minimum size requirement for DER aggregations that does not exceed 100 kW (171);
- Establish locational requirements for DER aggregations that are as geographically broad as technically feasible (204);
- Address distribution factors and bidding parameters for DER aggregations (225);

Order 2222 Compliance Directives

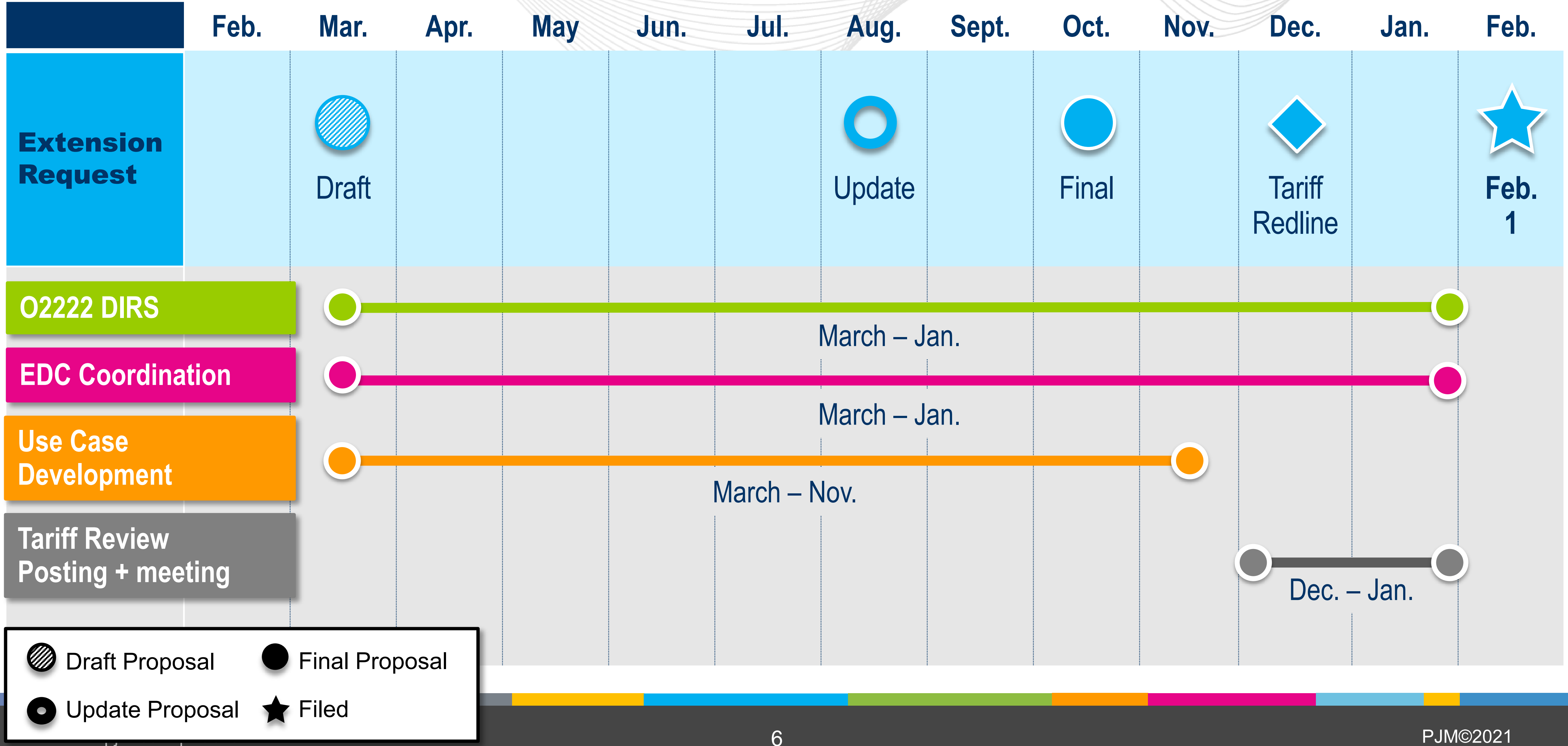
- Address information and data requirements for DER aggregations (236);
- Address metering and telemetry hardware and software requirements for DER aggregations (262);
- Address coordination between the RTO/ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities (”RERRA”) (278);
- Address modifications to the list of resources in a DER aggregation (335); and
- Address market participation agreements for DER aggregators via adoption of a standard market participation agreement for DER aggregations (352).

Compliance Filing Timeline

- FERC Grants Order No. 2222 Extension for PJM, and accordingly the new due date of PJM’s Order No. 2222 compliance filing is February 1, 2022.

- PJM to provided an informational filing containing a detailed stakeholder process schedule on May 10, 2021 and a status update August 9, 2021.
  - PJM will status reports every 90 days thereafter until the date that PJM submits its compliance filing.

Extension Timeline



- Presenting PJM's high-level holistic design approach and additional areas that need to be further defined
  – PJM is continuing to iterate on the design for DER aggregations to comply with FERC Order 2222
  – Continue to receive feedback from stakeholders and update proposal based on that feedback
  – Areas of large differing opinions from stakeholders will continue to be worked in DIRS

PJM Guiding principles for design development

- Compliance with FERC Order 2222 and 2222-A
- Remove barrier for market entry for DERs
- Uphold parity between models where applicable
- Maintain or enhance system reliability
- Simple implementation to evolve over time
  - Propose “check-in” point to re-evaluate part(s) of the design
  - Be able to accommodate and build out with DER operations into the future

Terminology

- **Distributed Energy Resource (DER):** any resource located on distribution, or distribution sub-system. Resource types include but not limited to Demand Response, Distributed Generation, Energy Storage, Electric Vehicles, & Energy Efficiency
- **Demand Response (DR):** any activity used to reduce load for the wholesale market
- **DER Aggregation (DERA):** An aggregation of one or more DER participating together in PJM Markets
- **DER Aggregator**: Market Participant for DERA

Order 2222 Design

DERA Jurisdiction & Interconnection	Operations	Market Design	Settlements	Coordination
1. Interconnection 2. Market Participation Agreements 3. Opt-in for Small Utilities	1. Locational Requirements 2. Distribution Factors 3. Telemetry 4. Operational Needs	1. Market Participation Model 2. Type of Technology (Homogenous / Heterogeneous) 3. Bidding Parameters 4. Min./Max. Size Requirements	1. Metering Configuration 2. Settlement requirements 3. Double Counting Services 4. Use case development	1. DER Registration 2. EDC Coordination 3. Modification to List of Resources

DERA Jurisdiction & Interconnection	
Interconnection	• PJM will not have jurisdiction of the interconnection of DER resources • DER owners will utilize the applicable state interconnection process without entering the PJM queue, if solely participating in a DERA provided a number of criteria are met
PJM Planning Requirements	• Data Requirements for Planning defined for necessary PJM study and reliability
Opt-in for Small Utilities	• Opt-in process for small utilities • Opt-out (large utilities) and opt-in (small utilities) requirements of Order Nos. 719 and 719-A still apply for Demand Response resources.
Market Participation Agreement	• Attestation that DERA is compliant with tariffs/operating procedures/rules of distribution utility and RERRA • Reviewing parties to Market Participation Agreement

- FERC makes clear in the Order that DER engaging in wholesale market activity through a DER Aggregation do not fall under a Commission-jurisdictional interconnection, stating the following:

- *We decline to exercise jurisdiction over the interconnections of distributed energy resources to distribution facilities for those distributed energy resources that seek to participate in RTO/ISO markets exclusively as part of a distributed energy resource aggregation. As such, only a distributed energy resource requesting interconnection to the distribution facility for the purpose of directly engaging in wholesale transactions (i.e., not through a distributed energy resource aggregation) would create a "first use" and any subsequent distributed energy resource interconnecting for the purpose of directly engaging in wholesale transactions would be considered a Commission-jurisdictional interconnection. (96-97)*

Interconnection

- PJM will not have jurisdiction of the interconnection of DER resources; however, a coordinated study including modeling must be provided for any delivery point where power injections can or have occurred prior to entering a DERA agreement.
- PJM will have oversight over the DER aggregation (DERA) participating in PJM markets.
- DER owners will utilize the applicable state interconnection process without entering the PJM queue, if solely participating in a DERA provided a number of criteria are met:
  - The DER satisfies the state interconnection requirements to interconnect
  - The DER satisfies any other applicable requirements to be eligible to participate in PJM's wholesale market in a DERA.
  - The impact of DER interconnected solely through state interconnection processes can be adequately represented in PJM power flow models for transmission planning purposes.
  - DER has a signed Interconnection Agreement with the applicable utility.

- If a DER does not satisfy the requirements for DERA participation, this resource will need to enter the PJM queue and be studied by PJM.
  - This DER will not be allowed to participate in a DERA and will be required to participate in PJM markets as a stand-alone resource.

- All resources will still have the opportunity of going through the queue, if they choose, or if a state interconnection process is unavailable.
  - These resources will not participate under the Order 2222 DERA model.

- Resources participating in a DERA, will not receive Capacity Interconnection Rights (CIRs) from PJM. However, those resources may be able to participate in the PJM Capacity Market through a nominated Capacity value for a DERA.

- DERs that successfully register with PJM as part of a DERA and receive a capacity value will retain their capacity accreditation, subject to having a valid State IA.

- With the integration of DERs participating in PJM Markets, PJM's transmission planning and RTEP process is currently being reviewed for any necessary updates to accommodate the DERs. Below are initial positions:

Status Quo for retail connected BTM DERs

- Current modeling represents DER activity on distribution as a reduction to load in the transmission models.
- Netted model may be sufficient for low levels of DER participation but will be inadequate if DERA spurs growth as intended by Order 2222.

Concerns with expanded DER participation and continued use of netted generation model

- Netted generation and loads are not visible to PJM's Planning analyses;
  - Generation and load have different characteristics;
  - Differences impact load flow analyses;
- Introduces reliability risks in scenarios where PJM must serve load

Concerns with expanded DER participation and continued use of netted generation model

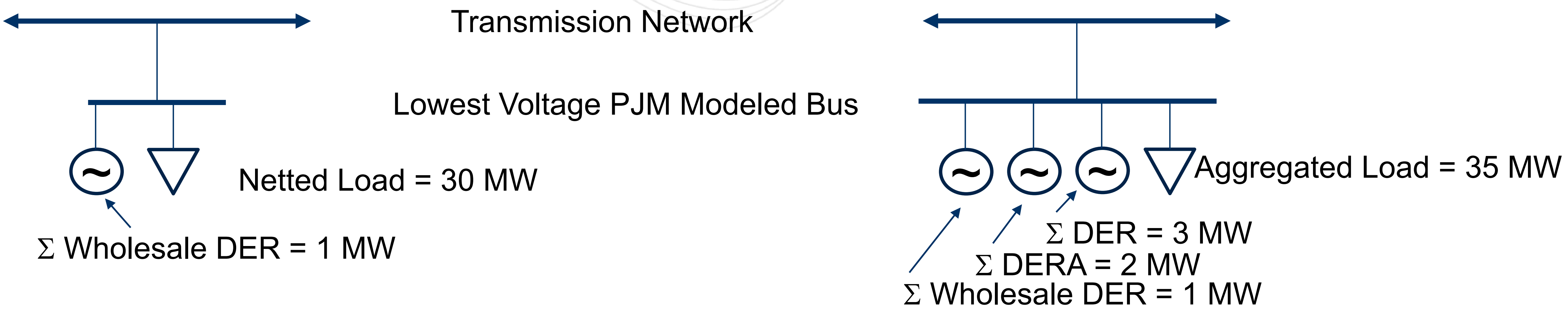
- NERC has issued several recent recommendations against netting; for example:
  - Reliability Guideline: Model Verification of Aggregate DER Models in Planning Studies (March 2021)
  - Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies (September 2020)

Proposed Data Requirements for Planning

- For each DER within a DER aggregation:
  - Address
  - Technology (solar, battery, landfill gas, wind, hybrid, etc.)
  - Maximum AC output (gross nameplate capability)
  - Interconnected distribution line identification
    - PJM plans to track distribution location and work with Transmission Owner to update transmission model, as necessary (Quality Assurance).
  - PJM Planning Model Bus ID distribution line is fed from
  - Ride through capability enabled? Y/N
  - Voltage control enabled? Y/N
- Both Aggregator and Electric Distribution Company will verify data annually

Simplified Example of Netted and Aggregated Modeling

Netted (current method) | Aggregated (proposed method)



Modeling Goal:

For any circuit with aggregate (non-wholesale DER) generation > 1MW, Transmission Owners will provide:

- aggregate load explicitly;
- aggregate DER generation explicitly (by fuel type);
- aggregate DERA participants explicitly separately (by fuel/participation type); and
- contingencies where combined aggregate DERA and DER generation ≥ 5 MW, and any aggregate load, can transfer to a different transmission bus.

Justification for Planning Data

- Provides better visibility of load and generation for PJM Planning;
- Improves PJM planning studies and transparency;
- Information should be readily available from participants; and
- Aids PJM in aligning with NERC and industry guidelines.

Jurisdiction

- Market-Based Rate Authority?
  - DER Aggregators intending to sell energy, capacity, or ancillary services at market-based rates will likely need Market-Based Rate Authority. (2222, n 94)
    - DER Aggregators should consult with their respective FERC counsel.
  - Order 2222 will not require individual DERs within an aggregation to have Market-Based Rate Authority.

- PJM Members?
  - DER Aggregator will need to be a PJM member to operate in PJM Markets.
    - DER physical owners will <u>not</u> need PJM membership.
  - DER Aggregator will be subject to credit requirements, based on the markets they are participating

- DERs NERC Registered?
  - Unlikely - does not meet the 75MVA threshold or the 100kV connection threshold (NERC ROP, Appendices 2 & 5B).
    - Questions should be referred to DER Aggregator’s FERC counsel regarding specific configurations.
  - This could change based on specific resources and further NERC advancement in DER activities.

Market Participation Agreements

- Likely will have parallels with the WMPA.
  - Notable exception: will be a *pro forma* agreement under the Tariff, so could in theory meet FPA 205(c) obligation via EQRs.

- Attestation that DERA is compliant with tariffs/operating procedures/rules of distribution utility and RERRA.

- *Market Participation Agreement & dispute resolution to be further detailed in September DIRS*

- *Accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year, and do not accept bids from DER aggregators if its aggregation includes DERs that are customers of utilities that distributed 4 million MWh or less in the previous fiscal year, unless the RERRA permits.*

- The opt-out (large utilities) and opt-in (small utilities) requirements of Order Nos. 719 and 719-A still apply for Demand Response resources.

- DR Opt-in/Opt-out process would apply to the following resources
  - Demand Response (load curtailment) resources
  - Resources participating with load curtailment and FTM injections in PJM Markets
    - Existing process for these resource in Demand Response
- Order 2222 Opt-in process would apply to the following resources:
  - FTM generator, energy storage, and energy efficiency resources
  - All resources within a heterogeneous aggregation.
- Possible transition period to be proposed for small utilities that do not opt-in and transition to a large utility (utilities that distributed more than 4 million MWh).

Operations	
Locational Requirements	• Nodal model to align with PJM dispatch and pricing • Primary location node will be identified in PJM system by EDC • All DER must primarily map to same node in order to aggregate to a DERA
Distribution Factors	• Referred to as “weighting factors” in proposal • Will not be used in initial implementation
Telemetry	• Telemetry will be required at the DERA level, for all DERA >0.1MW
Cyber Security	• PJM will implement cyber security at PJM’s “first hop” • Additional cyber security needed
Outage Reporting	• Outage reporting will be required for DERAs in capacity market

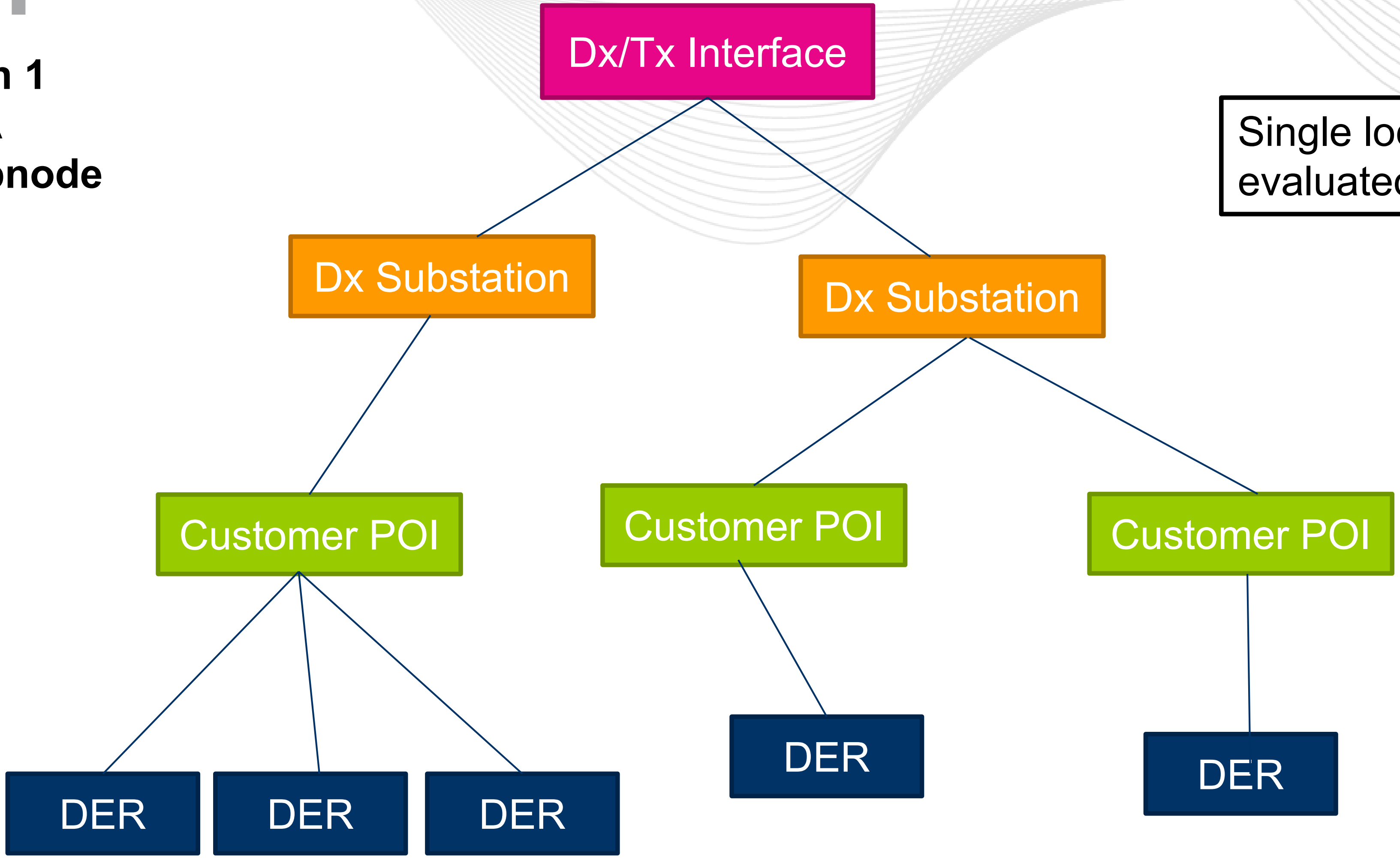
- *Establish locational requirements for DER aggregations that are as geographically broad as technically feasible (204);*

- Takeaways from previous discussions:
  - Concerns around transmission constraint control and accurate LMP formation with geographically broad aggregations
  - Operational concerns on distribution system with broad aggregations; especially across utility footprints
  - Improved market entry and lower chance of underperformance with broad aggregations for DERAs

Locational Requirements

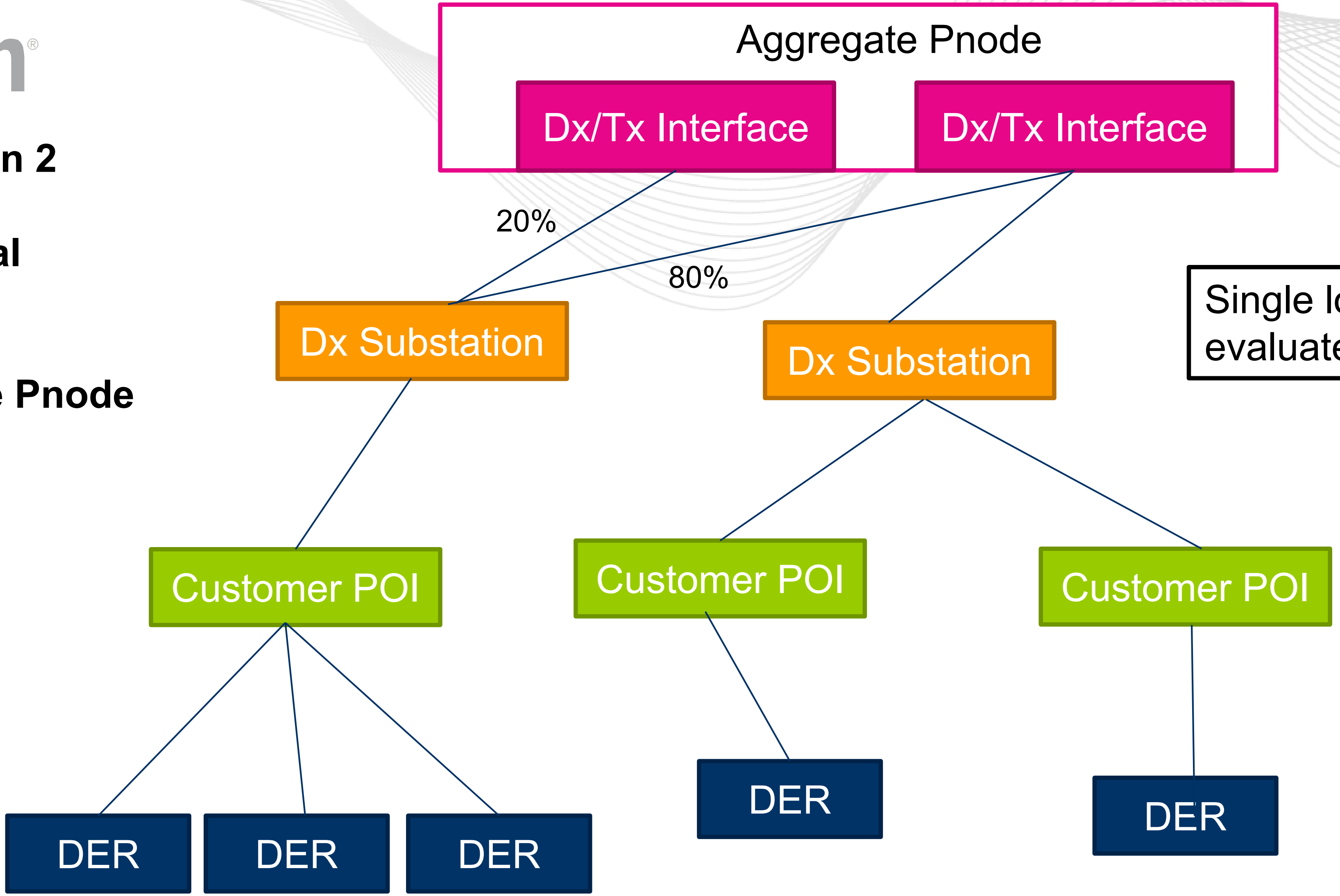
- What do locational requirements define for DERAs?
  - Locational requirements as discussed in this section will define how DERAs are modeled and dispatched for Energy & Ancillary Services.
    - These locational requirements will not necessarily define Capacity participation or Ancillary Service performance evaluations
- Each DER to be identified and mapped in the PJM network model
  - The location of each DER will be based on electrical impact and determined during the DERA registration process
- Each DER in a DERA will need to be a primary location (nodal modeling)
  - Weighting Factors will not be required from DERA in this model

Configuration 1
- **One DERA**
- **Priced at pnode**



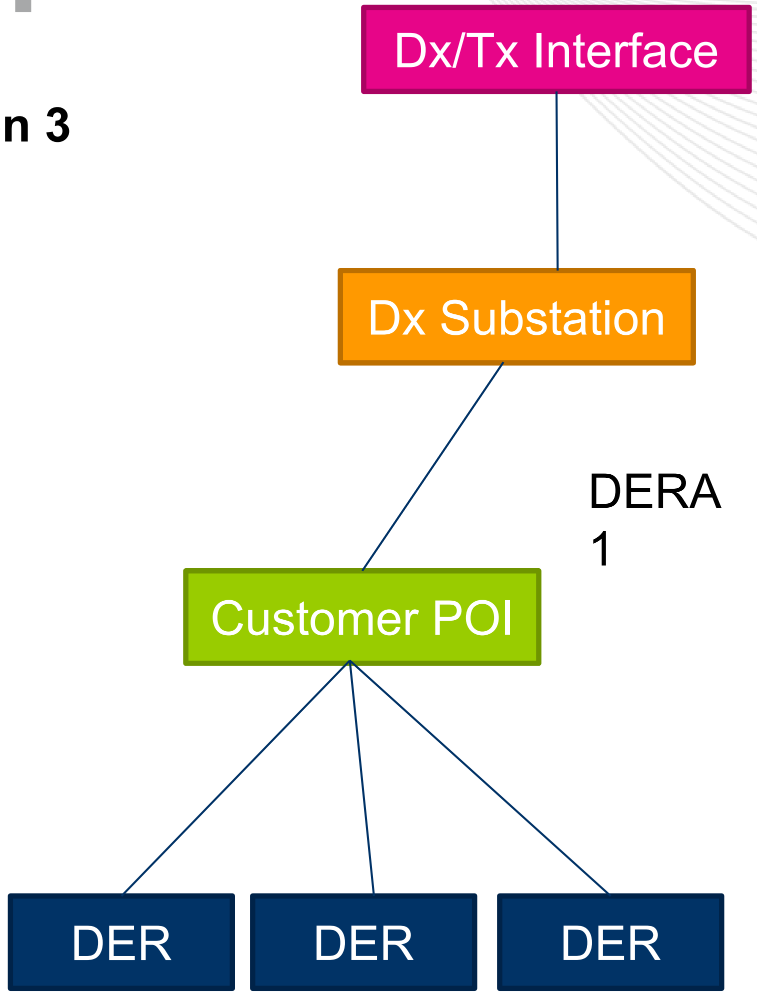
Single location requirement evaluated at the Dx/Tx Interface

Configuration 2
- One DERA
- **Split Nodal Mapping**
- **Priced at aggregate Pnode**

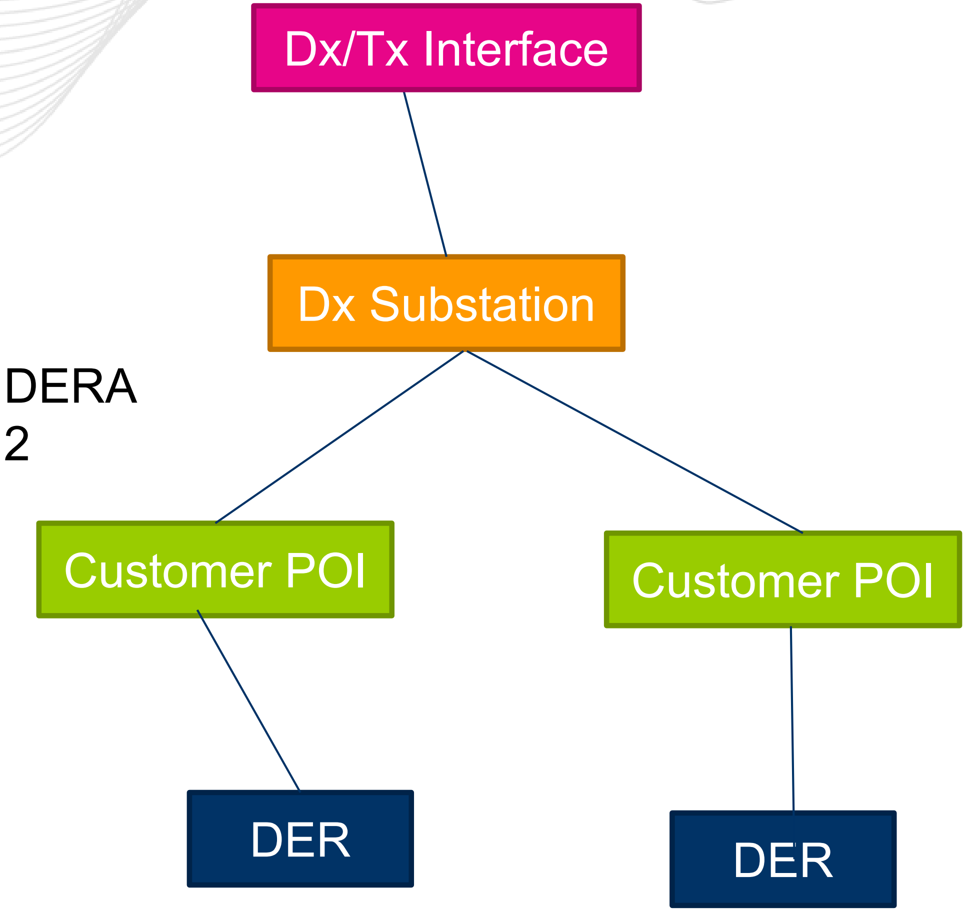


Single location requirement evaluated at the Dx/Tx Interface

Configuration 3 - Two DERA



Single location requirement evaluated at the Dx/Tx Interface



All the "Factors"

- (inputs/registration) **Capability Factors** (At DER level)
  - PJM will determine a capability factor, based on nameplate of DERs in a DERA. These will not be updated unless the aggregation changes and it is reviewed and approved by PJM/EDC.
- (inputs/registration) **Locational Factors** (At the DER level)
  - This is the mapping that the EDC/Aggregator provides for transmission location(s) (all DERs in aggregation sharing primary node), during registration process. This will not be updated unless reviewed and approved by PJM/EDC.
- (operations/markets) **Modeling Impact Factor** (At the DERA level)
  - The factor to be used in pricing/dispatch. It will be calculated from the capability factor and locational factor. There will not be a dynamic update of this value (hourly/daily) but can change over time if DERA changes occur (via registration process).
- (operations/markets) **Weighting Factors** (AKA "distribution factors" from Order 2222)
  - Defined as the breakdown of which DERs are responding to the dispatch signal – would be a RT update from the aggregator. Order ties this to multi-nodal aggregations.
  - Given we are using a "single location" approach, we will **not require weighting factors** for initial implementation.

Single Location Requirements

Registration – Managing Nodal Aggregations

DER	(Utility Review) Primary tranx. location	Size (MW)	Aggregation Definition	(Capability Factor) PJM calculated based on Size & DERA	(Locational Factor) Additional data from EDCs for modeling
DER1	Location 1	1	DERA 1	0.25	100% Node A
DER2	Location 1	1	DERA 1	0.25	100% Node A
DER3	Location 1	1	DERA 1	0.25	80% Node A, 20% Node B
DER4	Location 1	1	DERA 1	0.25	70% Node A, 30% Node D
DER5	Location 2	1	DERA 2	1	70% Node B, 30% Node A
DER6	Location 3	1	DERA 3	1	100% Node C

Defining Modeling Impact Factors

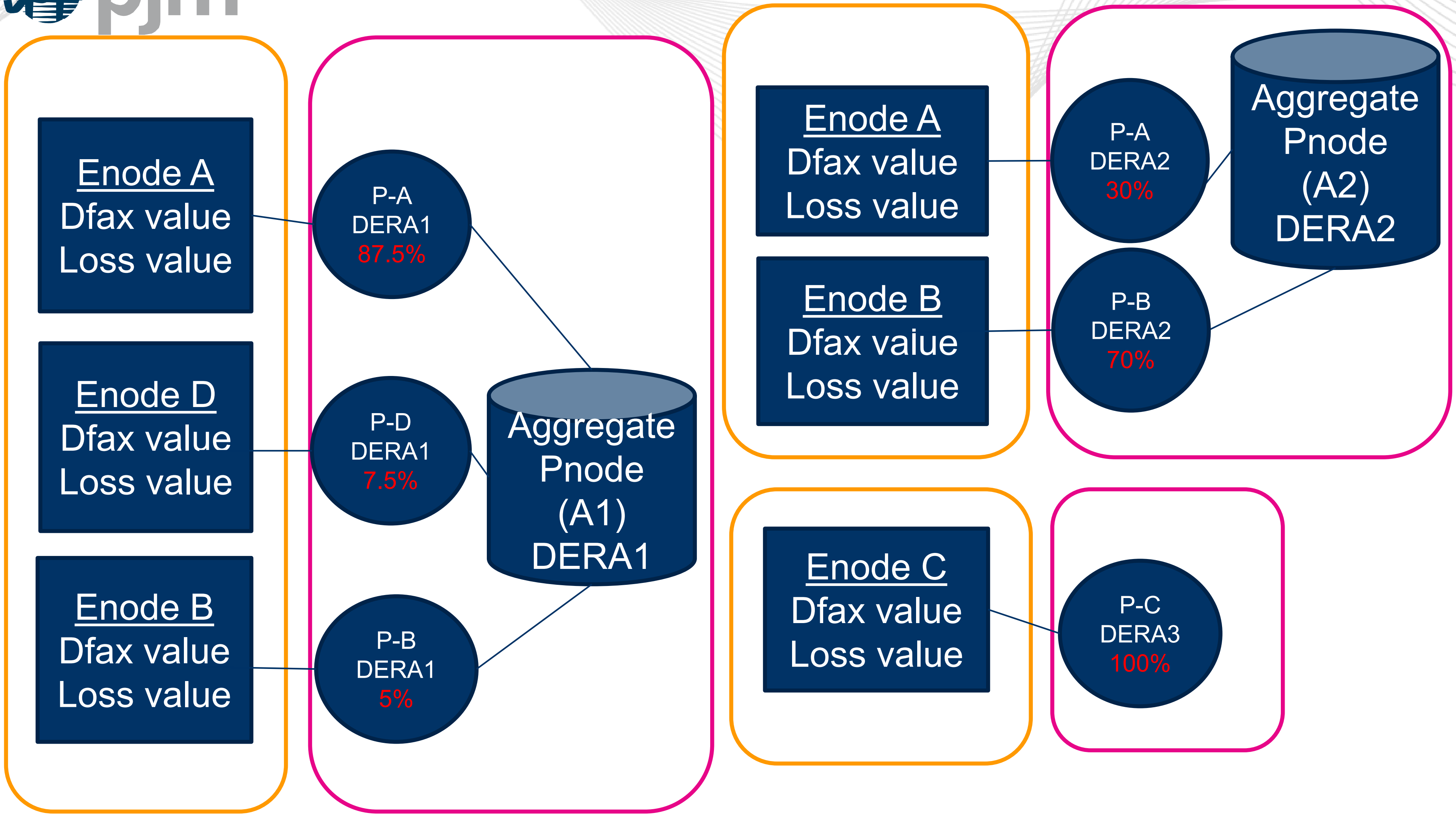
DER	Capability Factor	Aggregation Definition	Locational Factors	Modeling Impact Factors
DER1	0.25	DERA 1	100% Node A	0.25 – node A
DER2	0.25	DERA 1	100% Node A	0.25 – node A
DER3	0.25	DERA 1	80% Node A 20% Node B	0.20 – node A 0.05 – node B
DER4	0.25	DERA 1	70% Node A 30% Node D	0.175 – node A 0.075 – node D
DER5	1	DERA 2	70% Node B 30% Node A	0.70 – node B 0.30 – node A
DER6	1	DERA 3	100% Node C	1.0 – node C

DERA 1
0.875 – Node A
0.050 – Node B
0.075 – Node D

DERA 2
0.70 – Node B
0.30 – Node A

DERA 3
1.0 – Node C

Modeling Impact Factors – Implementation



- DERA locational requirements are single location or nodal
    - All DERs must map to 1 primary location
- Dispatch engine model is multi-nodal pricing (similar to combined cycles) when DERA is mapped to more than 1 node for proper operational modeling

Roles and Responsibilities

Data	Provided By?	Verified By?	When?
Capability/ Size (MW)	Aggregator	Utility	Registration
Capability Factor	PJM	PJM	Registration
Primary Location	Aggregator	Utility	Registration
Locational Factors	Utility	PJM/Utility	Registration
Modeling Impact Factors	PJM	PJM	After Registration
Weighting Factors	N/A	N/A	N/A

Proposal : No use of weighting factors provided in RT by aggregator to represent the operations/dispatch of underlying DERs in a DERA.

Locational Requirements – Why not multi-nodal?

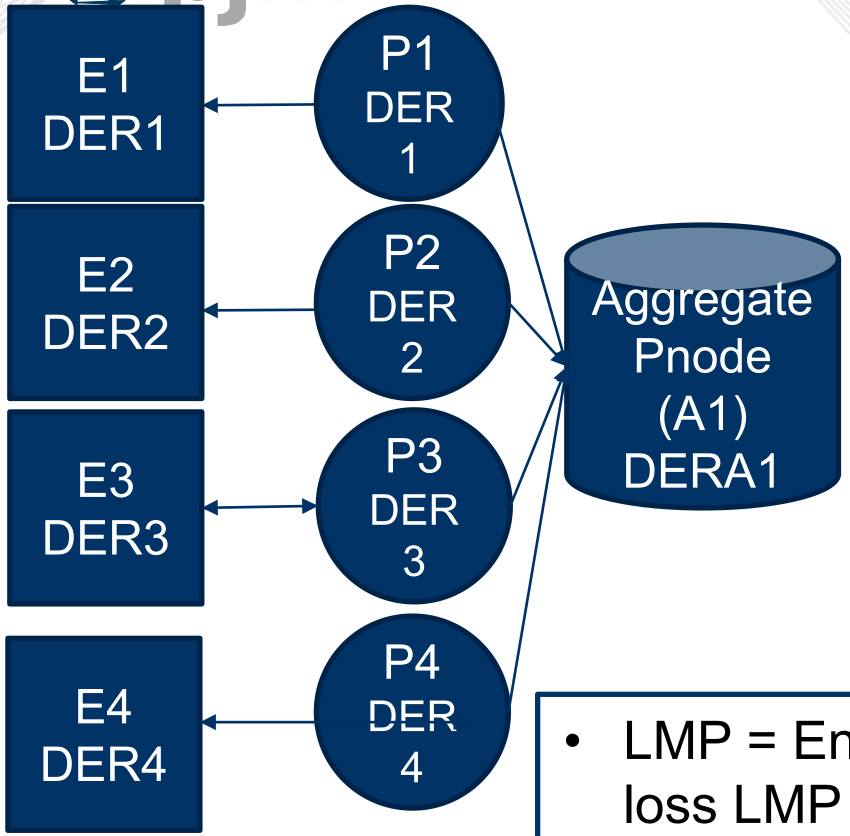
Definitions:

- **Enode =** A modelled electrical node in the PJM EMS model. An enode (or multiple enodes) can map to a pnode in Markets.
- **Pnode =** A pricing node in market model where an energy price (LMP) is calculated, pnode pricing data is available on Data miner 2.
- **Weight =** the portion of MWs that are coming from a specific DER/location within an aggregation. Summation of weight across an aggregation = 1.
- **Dfax =** Distribution factor representing the impact on a constraint for moving generation at that location. A negative value represents a raise-help to the constraint (increase generation helps to alleviate constraint) and a positive value is a lower-help (decrease in generation helps to alleviate constraints).

Locational Requirements - Introduction

- Assumptions:
  - Unlimited ramp capability and DERs will be on at full capacity or off at 0MW
  - Each DER has $20 cost to run
  - All DERs are mapped individually in EMS – based on electrical impact DERAs will be formed with 1 or more of the mapped DERs for Market Participation
- LMP = Energy LMP + sum of congestion LMP + loss LMP
  - Energy LMP = $25; Constraint binds at shadow price of -500; Loss LMP = 0
- Dfax for each node in example was taken from actual location(s) and constraint on PJM system.
  - These locations were close geographically.

Locational Requirements – Why not multi-nodal?



DER	Weight	Enode	dfax	LMP (pnode)
1	0.4	1	-0.468	$259
2	0.3	2	0.093	$-21.50
3	0.2	3	-0.145	$97.50
4	0.1	4	0.006	$22

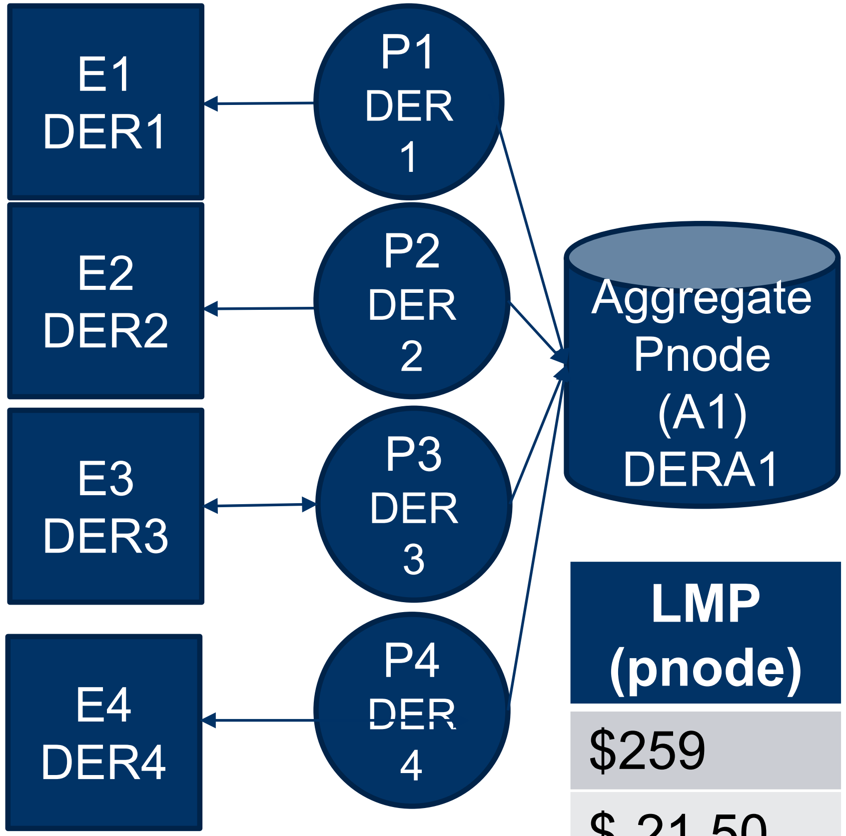
Aggregate A1 dfax = (0.4*-0.468)
+(0.3*0.093)+(0.2*-0.145)+(0.1*.006)
=(-0.1872+0.0279+(-.029)+0.0006)
= -0.1877

- LMP = Energy LMP + sum of congestion LMP + loss LMP
  - Energy LMP = $25, Constraint shadow price =-500, Loss LMP = 0
- A1 LMP = $25+(-0.1877 *-500) + 0
- A1 LMP = $25+$93.85 + 0
- A1 LMP = $118.85
- Dispatch of DERA (A1) = 1MW

- Creating an aggregate Pnode for multi-nodal aggregations will allow dispatch and pricing to capture only the resources in the aggregate
- Dispatch and pricing across nodes creates less accurate results.
  - DER2 would be dispatched to ecomax even though they are located at a negative LMP node. However, aggregate would be dispatched (as a whole) as a net help to the constraint.

Operations

Locational Requirements – Why not multi-nodal?



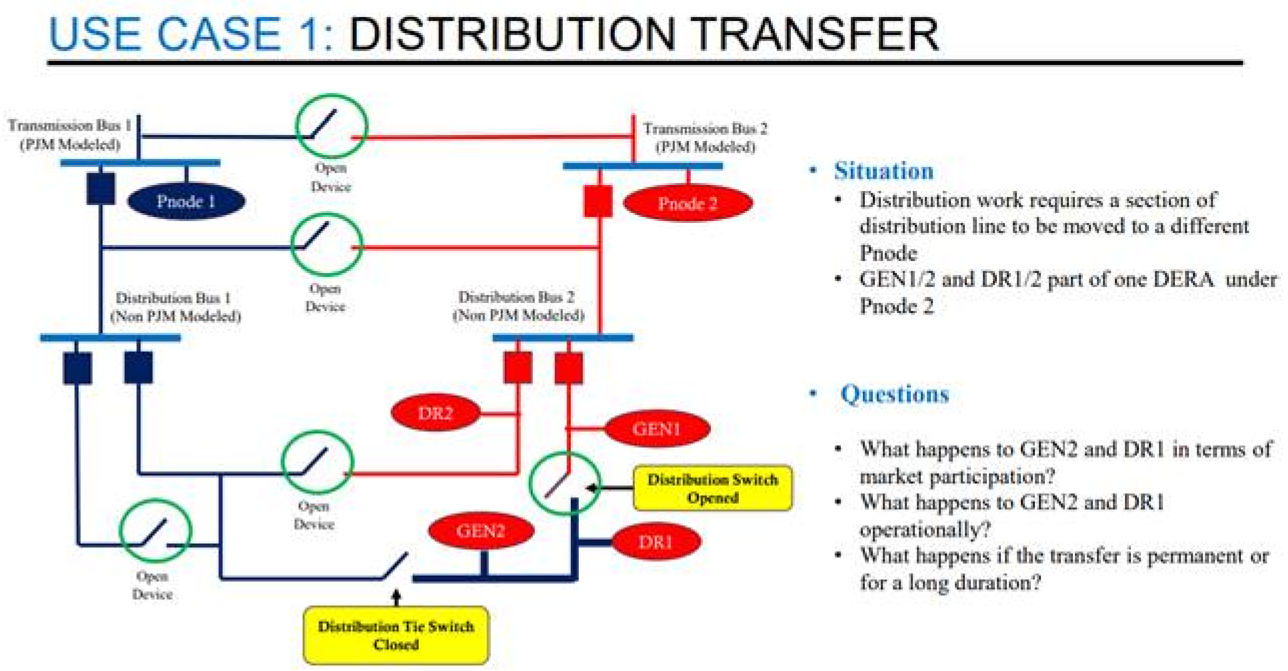
LMP (pnode)
$259
$-21.50
$97.50
$22

Day-Ahead	Real-Time
Weighting DER1 = 0.4 DER2 = 0.3 DER3 = 0.2 DER4 = 0.1 LMP = $118.85	Weighting DER1 = 1 DER2 = 0 DER3 = 0 DER4 = 0 LMP = $259

- Same MWs from the DERA, with different pricing dependent on weighting factors
- Example assumes same conditions in DA and RT

- Locational modeling can be updated but not intended to be dynamic on an hourly/daily basis
  - Modeling will be done on “normal” distribution configurations
    - Capturing dynamic updates in real-time for distribution system is unattainable
  - This will not impact DERA market participation and small inaccuracies may exist based on distribution switching
  - Long term changes will be addressed with a modeling update

Operational Changes

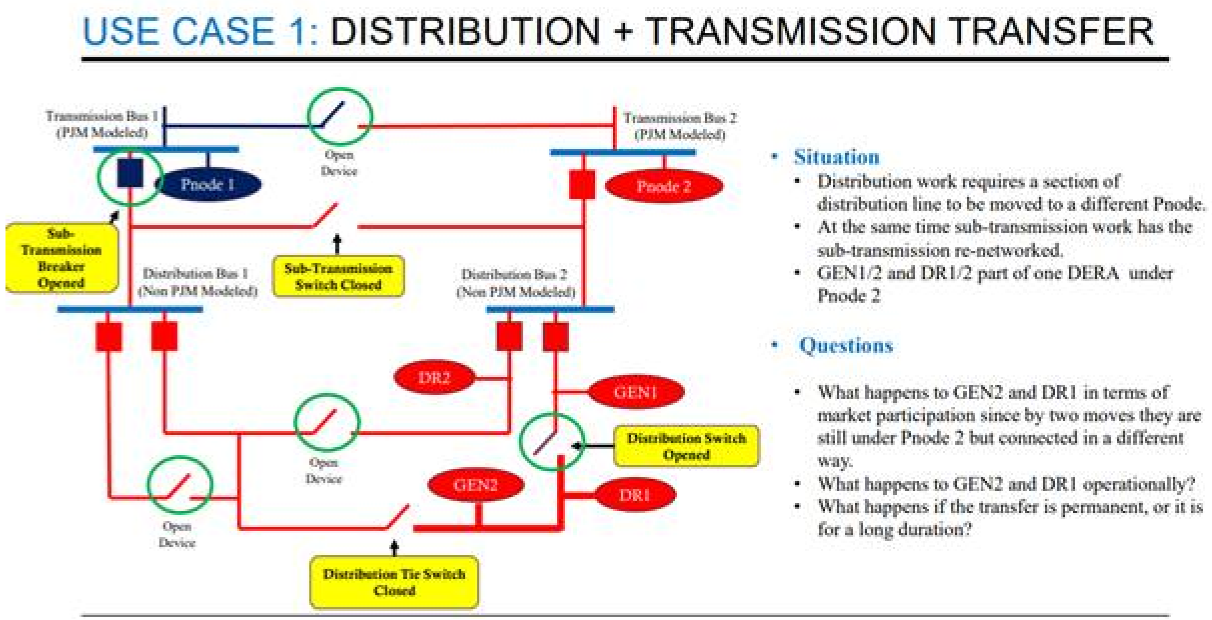


- **Market Participation:** DERA would still be able to participate at Pnode 2, even though flows would go over Pnode 1 and 2.

- **Operations:** DERA still able to participate in PJM. If EDC in unable to allow these resources to safely operate due to switching they should preform over-rides.

- **What happens if the transfer is permanent or for a long duration?** Modeling will be updated to reflect new “normal” distribution flows. This may result is splitting the DERA if locational requirements are no longer met

Operational Changes

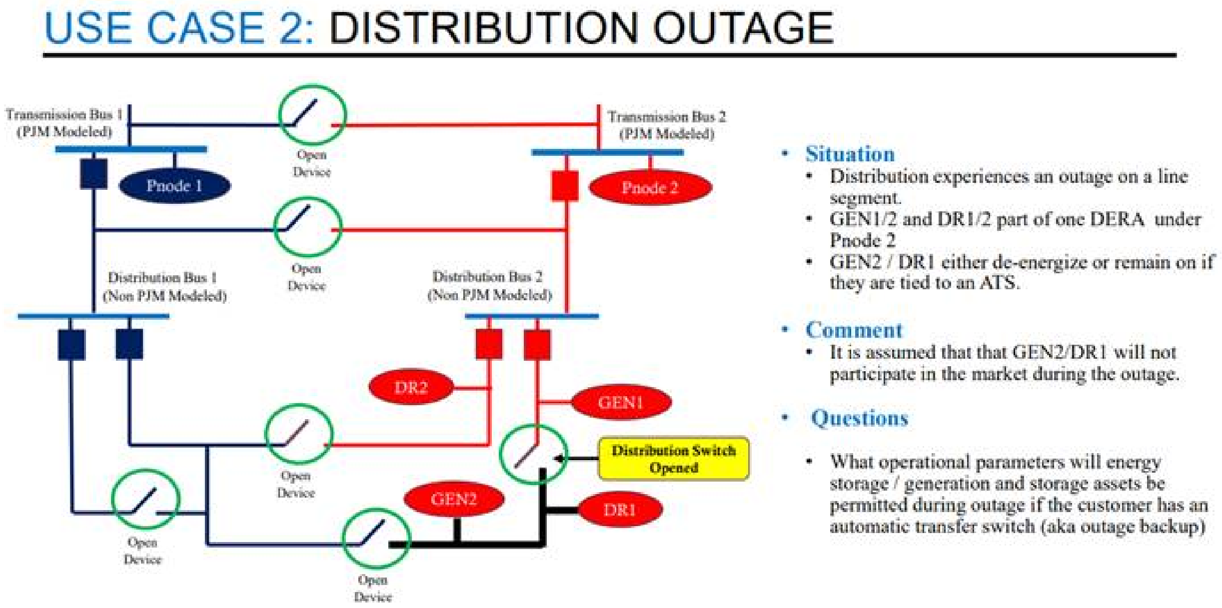


- **Market Participation:** DERA would still be able to participate at Pnode 2.

- **Operations:** DERA still able to participate in PJM. If utility has operational reliability concerns they should perform overrides, or raise any long term reliability impacts to PJM. Any long term reliability impacts would be addressed on case by case basis, but would ultimately not allow DERs to participate in wholesale market if there were safety and reliability concerns.

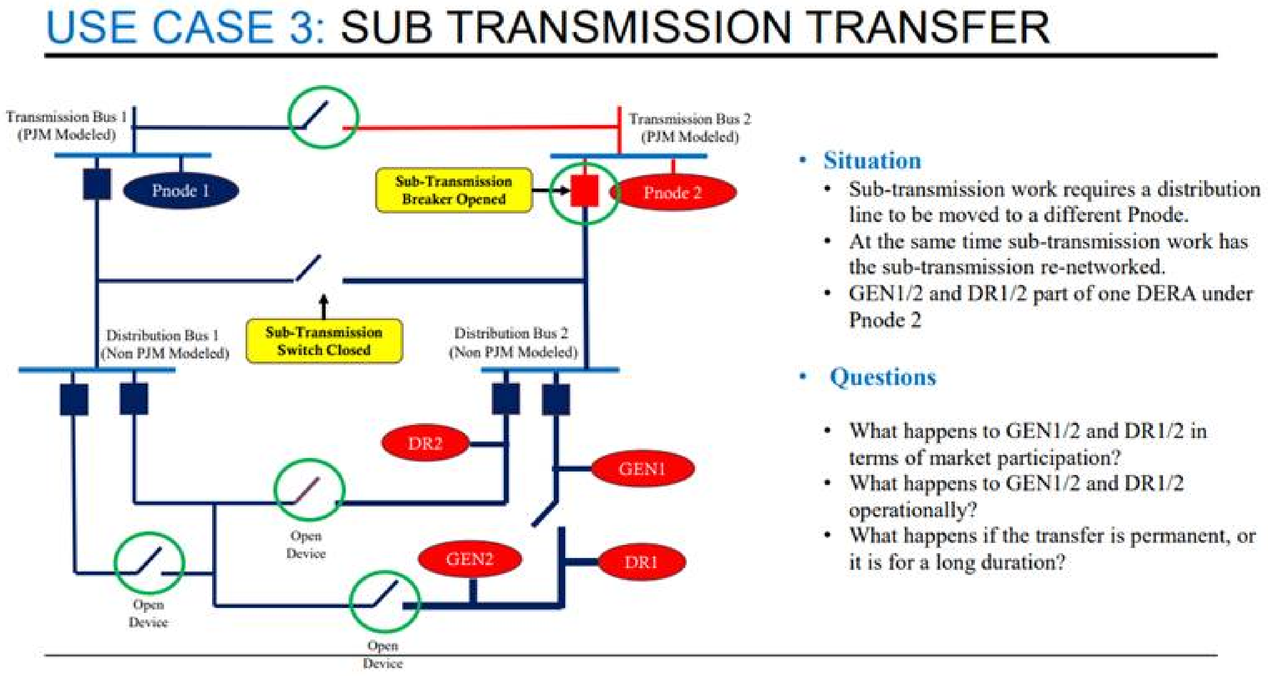
- **What happens if the transfer is permanent or for a long duration?** No changes as it still maps to same Pnode on PJM system

Operational Changes



- **Operations:** If there was an outage the de-energize part of a DERA we would expect parameter updates to reflect the decrease in capability for wholesale participation.
- Resource would not be able to provide back up power and be settled by PJM.

Operational Changes



- **Market Participation:** DERA would still be able to participate at Pnode 2, even though flows would go over Pnode 1 (assuming short term switching).
- **Operations:** DERA still able to participate in PJM. If EDC in unable to allow these resources to safely operate due to switching they should preform over-rides.
- **What happens if the transfer is permanent or for a long duration?** Modeling will be updated to reflect new "normal" distribution flows.

- Telemetry requirements are defining what data is being provided to PJM in real-time operations
  - After the fact meter data used for settlements discussed later in the proposal

- What DERAs have to provide telemetry to PJM?
  - Capacity & Energy Participation
  - Ancillary Service Participation – faster scan rates

Telemetry

- Aggregator will send telemetry values for the DERA to PJM
  - MW telemetry values sent in all cases
  - No MVAR data required to be sent to PJM
  - Transmit through Internet-based SCADA (Jetstream) or ICCP

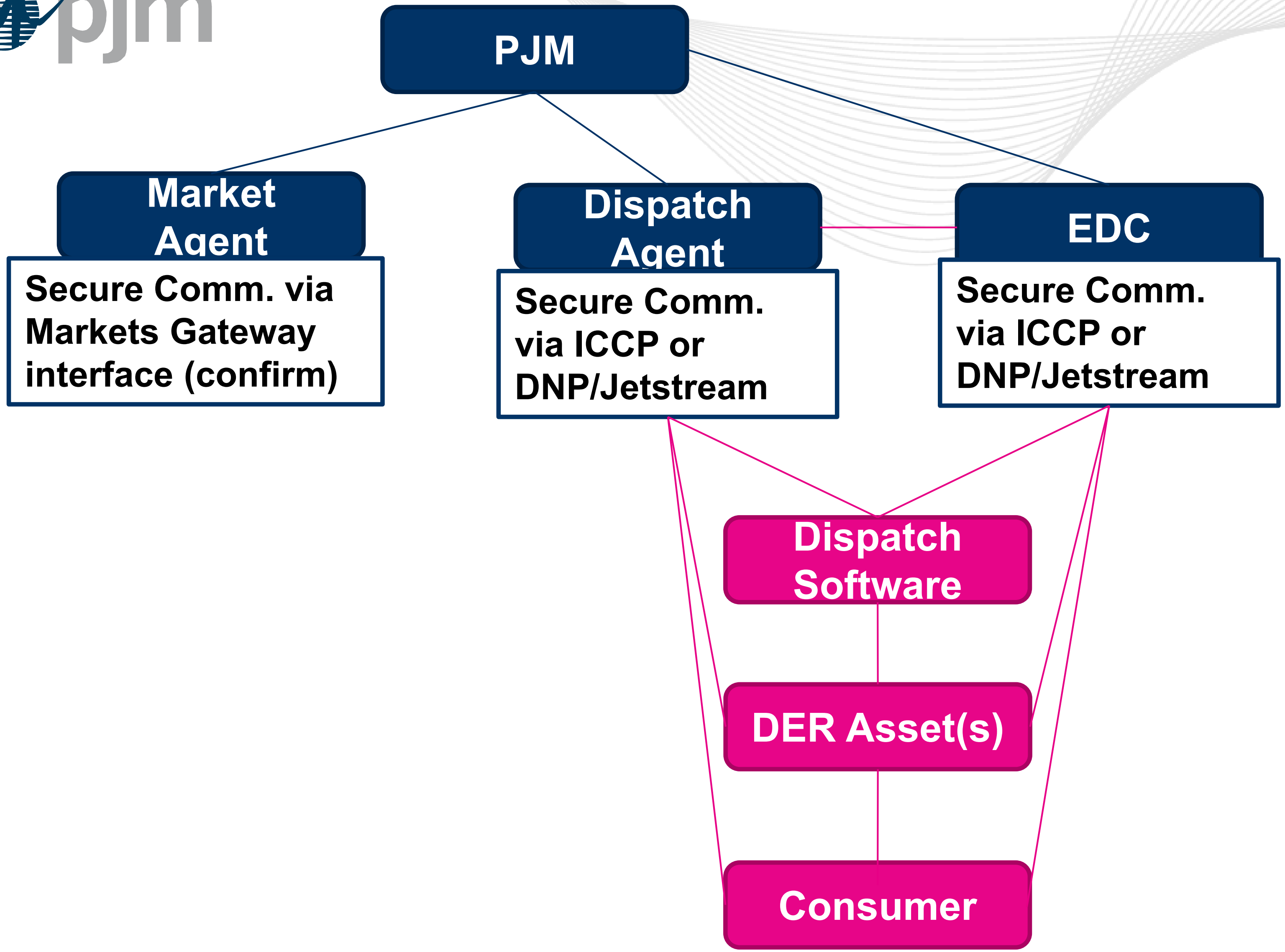
- Technology breakout telemetry will be needed for heterogeneous aggregations
  - ESR : State of charge information needed
  - Solar/Wind: Output needed for forecasting tools

Telemetry

- Point of measurement should be at interconnection point with EDC
  - Distribution losses should be accounted for in telemetry and agreed upon with EDC
- Aggregators may be expected to have individual DER telemetry data available (for EDC requests and/or audit purposes)
- Update Rate frequency determined by chosen market participation
  - Regulation Market: 2 second (Reg-D), 10 second (Reg-A)
  - Energy Market: 10 second

- Cyber Security
  - PJM will implement cyber security at PJM’s “first hop”
    - Aligned with CIP compliance
  - Further hops are not under PJM purview
    - Assume good security compliance further down the line governed by States and Utilities Jetstream with aggregator

Cyber Security



- Blue lines = PJM defined cyber security requirements
- Pink lines = Utility defined cyber security requirements

- Outage information will be needed for DER/DERA for capacity resources
  - Specific data needed for outages are still being evaluated by PJM
    - Determining if outage data needs to be reported at individual level or DERA level
    - Determining if there is a size/% based requirement for outage reporting for non capacity resources
    - Split out between load reductions (DR) and generating (DGR) DERs

Market Design	
Market Participation Model	• New “DERA” Market Participation Model, all existing model still available for participation • DERAs can participate in Energy, Capacity and Ancillary Services, where technically capable • DERs will be able to aggregate for market participation based on locational requirements for Energy. Further aggregation based on existing Capacity and Ancillary business rules are available.
Type of Technology	• Homogenous and Heterogeneous
Bidding Parameters	• Commitment variables not required • ESR model available to DERAs with ESRs
Size Requirements	• No minimum or maximum size requirements on DER • Minimum size requirement of 0.1MW for DERA

Market Design	
Capacity	• Planned DER will be eligible to participate • DERA CP Resources will be defined within a zone/sub-zonal LDAs • No must offer into capacity market for DERA
Energy	• No commitment model • DERAs can be dispatched by PJM by providing a cost offer to PJM or can self-schedule under a no-dispatch model • Must offer requirements for DERA (based on underlying DER)
Ancillary Services	• Eligible for regulation and reserves (sync and secondary) • Eligible to offer into Blackstart RFPs • Will not be used for Reactive Services

Market Participation Model

- DERs can participate under existing models or the proposed new “DERA” model.
- Existing models available to DERs to participate in PJM markets (if they qualify) are: Generator Model, Energy Storage Resource Model, Demand Response Model, Energy Efficiency Model
  - PJM is not proposing any modifications to business rules under those models at this time or any restrictions for DERs to continue to participate under those models (status quo)
- Market Products that will be available to DERA participants: Capacity, Energy, Ancillary Services

- Under the new DERA model
  - DERs can participate as an aggregation (one or more DERs) (DERA)
  - DERAs can be homogenous (include one resource/technology type) or heterogeneous (include multiple resource/technology type)
  - DERS at multiple locations (on distribution) can still be considered homogenous if they are made up of the same resource/technology DER

Managing Aggregations

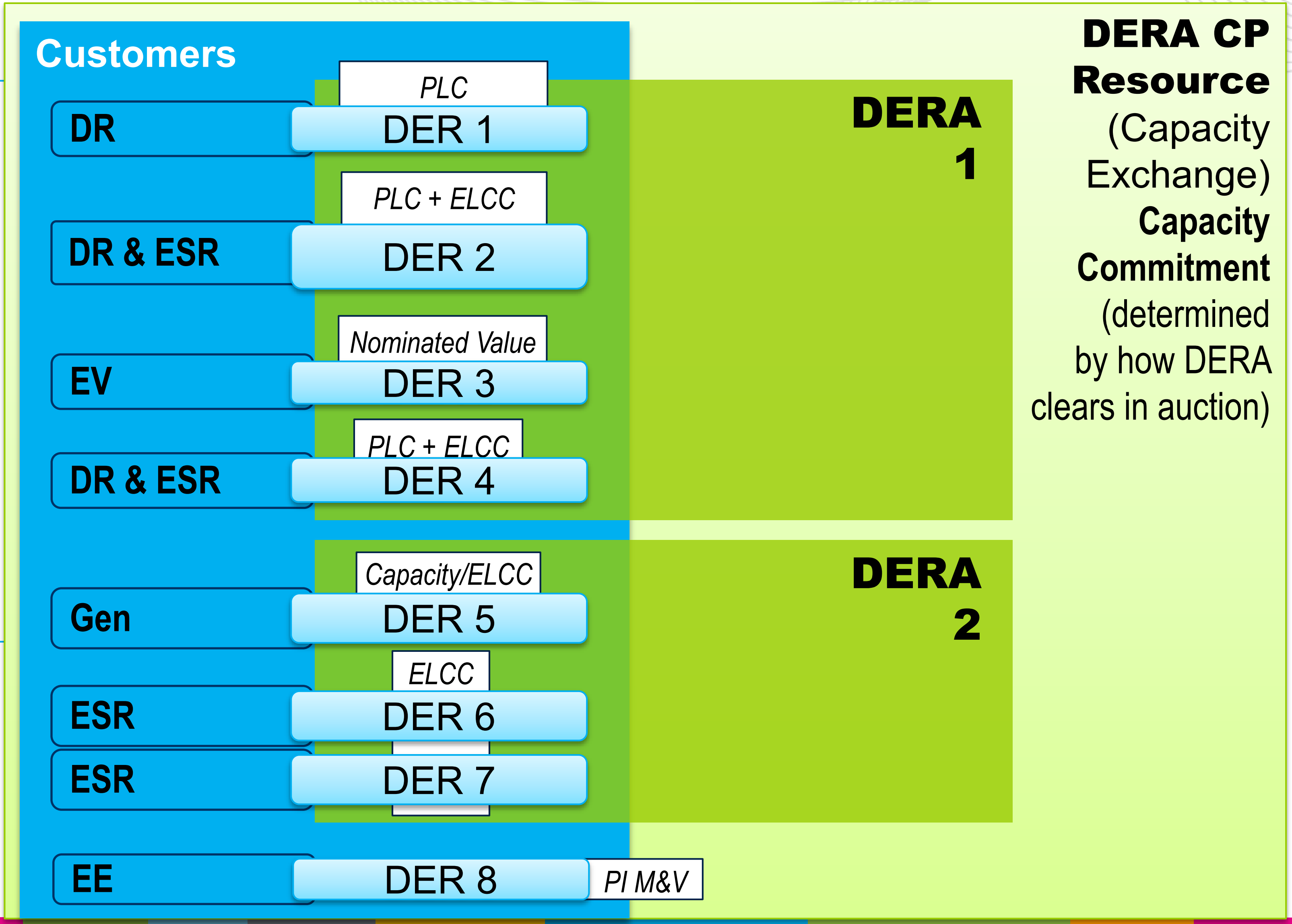
DER	(Utility Review) Primary transmission location	Aggregations for dispatch (locational reqts) –Energy & Ancillary	Aggregations for Capacity (DERA CP Resource)*	Aggregations for Ancillary Performance^
DER1	Node A	DERA 1	DERA CP 1	DERA 1, 2 & 3
DER2	Node A	DERA 1	DERA CP 1	DERA 1, 2 & 3
DER3	Node A	DERA 1	DERA CP 1	DERA 1, 2 & 3
DER4	Node A	DERA 1	DERA CP 1	DERA 1, 2 & 3
DER5	Node B	DERA 2	DERA CP 1	DERA 1, 2 & 3
DER6	Node C	DERA 3	DERA CP 1	DERA 1, 2 & 3

- *Meets LDA requirements in Capacity
- ^Meets Reserve Zone requirements for Reserves
- And performance group requirements for regulation

Market Participation Model

Registration/ Utility Review

- Define DERs in DERAs and capture necessary information
- DER aggregator, Location, Capacity Value, MOPR



Energy/ A/S Resource
- Market Resource ID
- Locational requirement defined
- Min = 100 kW
- Max = no max requirements

CP Resource
- Aggregation of many DERs across LDA
- Min = 100 kW
- Max = No max requirements
- Energy Resource cannot be split across DERA CP Resources

Capacity Value

Capacity

- Homogenous or Heterogeneous DERA CP Resource assigned to a zone/sub-zonal LDA based on the location of underlying DERs

- DERA CP Resource may voluntarily offer into the Capacity Market and is not subject to RPM Must Offer Requirement
  - Capacity value to offer based on capacity values calculated at the DER level and aggregated to the DERA CP Resource level
  - Offer price may be subject to MOPR and MSOC based on the underlying DERs

Capacity

– Non-Performance Assessment applies to a committed DERA CP Resource
  - Subject to Non-Performance Charge if underperform and subject to Bonus Performance Credit if over-perform
  - Actual Performance will be calculated at DERA level (energy market resource level)
    - Exception for Energy Efficiency
  - Excusals for outages (assuming an approved outage during PAI)
  - No dispatch excusal if dispatched or overrides by utility for reliability
  - Netting of performance will be available for DERAs within the DERA CP Resource
    - No netting of performance across DERA CP Resources in a market seller account

Market Participation Model

- DERAs within a defined zone/sub-zonal LDA can aggregate to a DERA CP resource
- (1) Capacity value is assigned at the DER level and added to determine the DERA Capacity value (DERA 1, DER 2 in example below)
- (2) Committed Capacity is at the DERA CP Resource
  - May have more registered capacity value than is needed to satisfy the DERA CP Resource commitment
  - Committed capacity may be less than 0.5MW

DERA CP RESOURCE 1 : 0.5MW Capacity

<u>DERA1 0.4MW capacity value</u>

DER1: 0.1MW capacity value
DER2: 0.1MW capacity value
DER3: 0.2MW capacity value

<u>DERA2 0.1MW capacity value</u>

DER4 : 0.05MW capacity value
DER5: 0.025MW capacity value
DER6: 0.025MW capacity value

Capacity Participation

- **Planned DER** will be able to participate in the Capacity Auction under certain circumstances.
  - Planned DER will be able to participate by submitting a plan to PJM, with an attestation on deliverability, to be able to offer into a Capacity auction prior to the DER being operational
  - Technology, number of customers and zone/subzone LDA needs to be identified. Site-specific information needed in a zone of concern.
  - Planned DER will offer in as DERA CP resource with minimize size requirements of 0.1MW

Capacity Participation

- **Emergency DER** will be ineligible to participate in Capacity under a DERA.
  - DER that is Pre-Emergency/Emergency load response will not be able to participate in a DERA CP Resource.
  - Pre-Emergency/Emergency load response will still be able to participate in Capacity Demand Resource
- Must Offer Requirement in DA Energy Market is being extended to DERA CP Resources
  - Need visibility into the planned operation of these resources under high penetration levels.

Energy

- Two options for Energy Dispatch available under DERA Model
  - Option 1: DERA will participate in Energy under a no-commitment, no-dispatch model.
  - Option 2: DERA will participate in Energy under a no-commitment model, PJM dispatch available
  - DERAs with underlying storage will have access to participating under the ESR model to reflect charging

Energy

- no-commitment, no-dispatch model
  - DERAs will be expected to self-schedule energy into the DA and RT energy markets based on their forecasted availability.
  - DERAs will be required to submit $0 cost based offers.
  - DERAs will not be eligible for LOC or make whole.
- no-commitment, PJM dispatch model
  - Homogeneous DER aggregations will follow Manual 15 language and construct FCP for non-zero cost based offers.
  - Heterogeneous DER aggregations will have zero cost based offers. There is an opportunity to develop cost based offers in the future at the Cost Development Subcommittee.
  - DERAs will be eligible for LOC or make whole if manually dispatched.

Ancillary Services

- DER aggregations (DERA) will be allowed to participate in the following Ancillary Service markets
  - (1) regulation
  - (2) reserves
- DERAs will be eligible to offer resources into Black Start RFPs for consideration on Black Start Service
  - DERAs would be evaluated on a case-by-case basis based on RFP response
- DERAs will not be considered for Reactive Support or required to provide VAR data to PJM

Ancillary Services - Reserves

- DERAs will follow the same business rules as detailed in Manual 11 Section 4 for reserves.
  - DERAs are ineligible to provide non-synchronized reserves
    - DERAs will be self-committing into PJM's Market and therefore will be considered synchronized when scheduled. Will be considered offline/unavailable when not self-committed
  - DERAs will need to contained within a predefined reserve zone or subzone
    - Single node locational model should address this requirments
  - Under the new reserve pricing model (May 2022), DERAs will be eligible for secondary reserves participation, given they have a valid energy offer.
  - DERAs will have the opportunity to participate in Reserves as a "Reserves Only" resource, or as ancillary participation to energy.

Ancillary Services - Reserves

- DERAs, by default, will not be considered for reserves, based on underlying technology, but may request an exception to participate.
  - Follow proposed process for Reserve Pricing eligibility that was presented at June 30, 2020 MIC Special Session – Reserve Price Formation Order
    - https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200630-special/20200630-item-03a-resource-eligibility-for-reserves-proposal.ashx

Ancillary Services - Regulation

- DERAs will follow the same business rules as detailed in Manual 11 Section 3 and testing requirements as detailed in Manual 12 Section 4.5 for regulation.
  - DERAs are eligible to provide regulation service
  - DERAs can participate in Regulation as a stand-alone aggregation, or utilize performance groups to aggregate performance over multiple aggregation
  - DERAs will have the opportunity to participate in Regulation as a "Regulation Only" resource, or as ancillary participation to energy.

Min/Max Size Requirements

- *Establish a minimum size requirement for DER aggregations that does not exceed 100 kW (171)*
- *Direct each RTO to propose a maximum capacity requirement for individual distributed energy resources participating in its markets through a distributed energy resource aggregation or, alternatively, to explain why such a requirement is not necessary (179)*
- *Does not adopt a maximum size requirement for distributed energy resource aggregations that span multiple pricing nodes. (174)*

Sizing Requirements for DERs (individual resources)

- No minimum or maximum size requirements will be defined.

- Interconnection requirements and DERA participation requirements allow PJM to not implement a maximum size requirement and still uphold reliability
  - Maximum size will be determined by the EDC/TSO based on system characteristic of the interconnected facility

Sizing Requirements for DERA (aggregation resource)

- Minimum size requirements for DERA will be 100kw for Market participation
  - Existing requirement for market participation
- No maximum size requirements for DERAs.
  - Single locational model will not require a maximum for DERAs

Settlements	
Metering Configuration & Requirements	• Data submissions for settlements will follow existing PJM Powermeter and Inschedule requirements
Settlement Requirements	• Uphold Order 745 for DR Settlements
Double Counting Services	• Double counting will not be permitted participating in PJM Markets • Determination of double counting due to retail activity will be determined by the EDC
Use Case Development	• List of use cases to test proposal requirements

- Existing Metering Requirements located in Manual 14D
  - Section 4.2.2: Metering Plan
  - Section 4.2.3: Metering for Individual Generators
    - *"…a Generation Owner can negotiate data transmission to and from PJM through the local utility or transmission facilities owner. This allows the Generation Owner the flexibility to use already proven and acceptable methods of data transfer to* ***minimize initial startup costs and procedures, while meeting all of the current requirements*** *for providing data to PJM."*
    - *"…can be supplemented with the use of the Internet-based PJM Tools such as inSchedule and Data Viewer, further expanding the data transfer capabilities between the customer and PJM without a direct connection to PJM."*

Metering

- Real-time (RT) revenue data is required to be submitted into PowerMeter either on a 5 minute or hourly basis in accordance with Manual 28, sections 1A and 3
  - Current PowerMeter and InSchedule deadlines – PowerMeter is next business day
- MW data true up
  - Generator RT MWh use the One-Month-Lag Meter Correction process via PowerMeter
  - LSE RT load MWh use the Two-Month-Lag Load Reconciliation process via InSchedule (needed because generator metering updated)

- Meter data may be submitted as an aggregation, but for the following types of DER resources, which need to be individual:
  - Demand Response (through DR Hub)
  - Energy Storage
  - DERS participating in Capacity
  - Heterogeneous aggregations
- PJM needs the ability to properly settle MWh for different types of DERS

- PJM will settle Demand Response resources participating in a DERA (homogeneous or heterogeneous) with Order 745 requirements.
- Demand Response resources that wish to participate in a DERA will have the following additional requirements
  - Submit metered data to PJM by the PowerMeter deadline (1 business day after the Operating Day)
    - PJM is currently evaluating all options for changing this
  - Be mapped at a pricing node (instead of the zonal residual aggregate)

Settlements – Day-ahead

- DER units and DERA which clear day-ahead will be settled as day-ahead spot market at the LMP which they cleared

- If any demand response resources are in a DERA, the actual real-time load reduction will be used to carve out the DR activity
  - For any demand response MWs, the day-ahead load of the associated LSE will be adjusted
  - Demand Response MWs will be settled following demand response business rules.

Demand Response Clearing Day-ahead

- Whenever a Demand Response resource clears day-ahead, PJM applies a negative load bid in day-ahead to the LSE associated with the registration.

- This negative load bid will be referred to as the negative dec bid during this presentation.

DERA with Demand Response

- For any DERA which contains demand response (whether a heterogeneous or homogeneous DERA), PJM will be applying a negative dec to the LSE for any cleared day-ahead bids.

- Since many LSEs can be affected by demand response resources at the same pricing point, PJM will need to know the percentage of response each resource will be responsible for in the day-ahead market.

- This is the same process PJM currently uses DR Dispatch Groups which clear day-ahead.

Requirements for Negative Dec

- If PJM is receiving metered date for demand responders on the PowerMeter deadline (next business day), PJM will require no additional data from the aggregators.
  - PJM will apply a actual relief to the day-ahead market as a negative dec associated with each LSE effected.
- If PJM is receiving metered date for demand responders on the PowerMeter deadline, PJM will need to know the ownership share for each resource in the DERA.
  - This same ownership share will be used to apply an actual day-ahead settlement for demand response energy market.

Ownership Share

- Ownership share will be defined as the percentage of the total DERA’s load that each DR registration is responsible for.

- Currently the resources within a DERA will be registered annually, however, if this does change, PJM will need a new ownership share value whenever resources are removed or added to a DERA.

- DER units and DERAs which clear day-ahead will be settled for any deviations from day-ahead commitments in the balancing spot market
  - When dispatched in real-time, the day-ahead commitment will be zero
- Any demand response in a DERA will have any reduction above their expected amount carved out and settled as real-time load response

- With DER and DERA being modeled as no-commitment units, DER and DERA units that clear Day-ahead or are Dispatched by PJM in real-time will not be eligible to receive Operating Reserve Make-whole Credits, unless they are manually dispatched by PJM

- DER and DERA resources can receive Operating Reserve Deviation Charges. Currently PJM is evaluating whether DERA will be evaluated for deviations at the aggregate or nodal level

Settlements – Demand Response

- FERC Order 2222 states that PJM will need to still follow FERC Order 745 rules when settling DR in a DERA
  - Any DR resources in a DERA will have their settlements calculated following demand response business rules
  - PJM is evaluating whether the Net Benefits Test will be performed at the nodal price or the weighted average LMP of the aggregate

- DR Resources within a DERA will only be eligible to receive operating reserve make-whole credits if the aggregate is eligible to receive operating reserve make-whole credits

Generator LMP Charge Summary

Generator LMP Charge Summary																			150	2.5	1.25	
4000.01	4000.02	4000.05	...	4001	4001	3000.8	4000.19	4000.2	3000.32	3000.01	1200.11	3000.06	1210.18	3000.15	1220.18	3000.33	3000.91	1205.11	1215.2	1225.2	4000.07
Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Unit ID	Unit Name	Unit Ownership Share	PNODE Name	PNODE ID	EPT Hour Ending	DA Scheduled MWh	DA PJM Energy Price ($/MWh)	DA Spot Market Energy Charge ($)	PNODE DA Congestion Price ($/MWh)	DA Transmission Congestion Charge ($)	PNODE DA Loss Price ($/MWh)	DA Transmission Loss Charge ($)	RT Generation (MWh)*	Bal Generation (MWh)	Bal Spot Market Energy Charge ($)	Bal Transmission Congestion Charge ($)	Bal Transmission Loss Charge ($)
...	...	07/01/2021 10	...	...	...	1	DERA PNODE 1	...	10	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 11	...	...	...	1	DERA PNODE 1	...	11	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 12	...	...	...	1	DERA PNODE 1	...	12	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 13	...	...	...	1	DERA PNODE 1	...	13	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 14	...	...	...	1	DERA PNODE 1	...	14	5	100	-500	0.25	-1.25	-1.5	7.5	4	-1	150	2.5	1.25
...	...	07/01/2021 15	...	...	...	1	DERA PNODE 1	...	15	5	100	-500	0.25	-1.25	-1.5	7.5	5	0	0	0	0
...	...	07/01/2021 16	...	...	...	1	DERA PNODE 1	...	16	5	100	-500	0.25	-1.25	-1.5	7.5	5	0	0	0	0
...	...	07/01/2021 17	...	...	...	1	DERA PNODE 1	...	17	5	100	-500	0.25	-1.25	-1.5	7.5	5	0	0	0	0
...	...	07/01/2021 18	...	...	...	1	DERA PNODE 1	...	18	5	100	-500	0.25	-1.25	-1.5	7.5	5	0	0	0	0

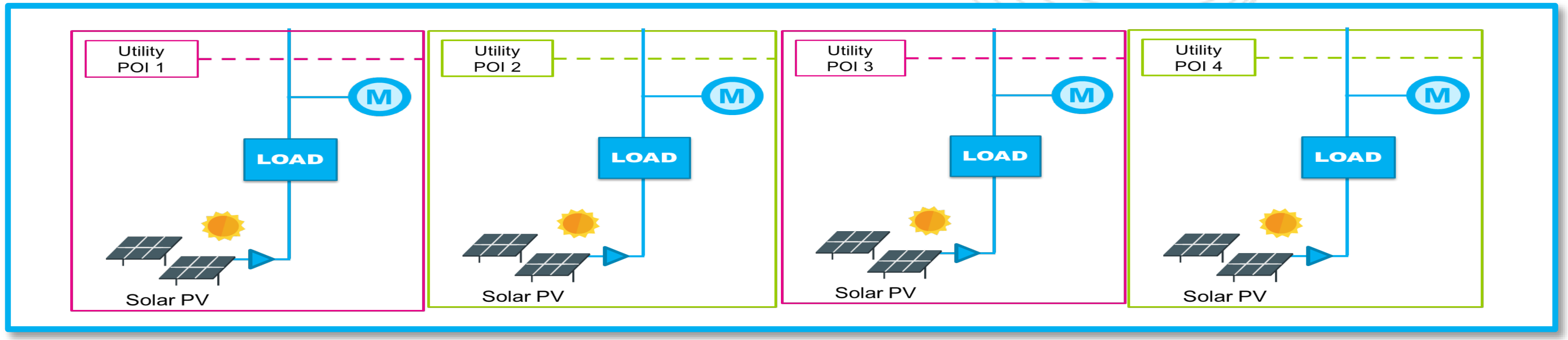
Load Response Summary

4000.01	4000.02	4000.03	4000.05	4000.1	4000.9	4000.94	4000.95	4000.32	3000.32	3001.14	3000.24	1240.11	2240.01	1240.01	1241.11	1241.12	1241.13	3000.83	3001.15	3000.25	1241.14	2241.01	1241.01
Customer ID	Customer Code	Billing Month	EPT Hour Ending	GMT Hour Ending	Registration ID	EDC Account Number	End Use Customer	Zone	EPT Hour Ending	DA Load Response MWh	DA LMP ($/MWh)	DA Retail Rate Used ($/MWh)	DA Load Response Credit ($)	DA Load Response Charge ($)	CBL (MWh)	Metered Load (MWh)	Load Response Loss Factor	EDC Loss De-ration Factor	RT Load Response MWh	RT LMP ($/MWh)	RT Retail Rate Used ($/MWh)	RT Load Response Credit ($)	RT Load Response Charge ($)
123456	ABCDEF	7/1/2021 04	07/01/2021 10	07/01/2021 14	R1234	12341	DERA DR Reg	PE	10	3	100	0	300	0	5	3	1.01	0.01	1.9998	150	0	-150.03	0
123456	ABCDEF	7/1/2021 04	07/01/2021 11	07/01/2021 15	R1234	12341	DERA DR Reg	PE	11	3	100	0	300	0	5	2	1.01	0.01	2.9997	150	0	-0.045	0
123456	ABCDEF	7/1/2021 04	07/01/2021 12	07/01/2021 16	R1234	12341	DERA DR Reg	PE	12	3	100	0	300	0	5	4	1.01	0.01	0.9999	150	0	-300.015	0
123456	ABCDEF	7/1/2021 04	07/01/2021 13	07/01/2021 17	R1234	12341	DERA DR Reg	PE	13	3	100	0	300	0	5	3	1.01	0.01	1.9998	150	0	-150.03	0
123456	ABCDEF	7/1/2021 04	07/01/2021 14	07/01/2021 18	R1234	12341	DERA DR Reg	PE	14	3	100	0	300	0	5	2	1.01	0.01	2.9997	150	0	-0.045	0
123456	ABCDEF	7/1/2021 04	07/01/2021 15	07/01/2021 19	R1234	12341	DERA DR Reg	PE	15	2	100	0	200	0	5	2	1.01	0.01	2.9997	150	0	149.955	0
123456	ABCDEF	7/1/2021 04	07/01/2021 16	07/01/2021 20	R1234	12341	DERA DR Reg	PE	16	2	100	0	200	0	5	4	1.01	0.01	0.9999	150	0	-150.015	0
123456	ABCDEF	7/1/2021 04	07/01/2021 17	07/01/2021 21	R1234	12341	DERA DR Reg	PE	17	2	100	0	200	0	5	5	1.01	0.01	0	150	0	-300	0
123456	ABCDEF	7/1/2021 04	07/01/2021 18	07/01/2021 22	R1234	12341	DERA DR Reg	PE	18	2	100	0	200	0	5	5	1.01	0.01	0	150	0	-300	0

- **Double Counting Services:** limit the participation of resources in RTO/ISO markets through a distributed energy resource aggregation (DERA) that are receiving compensation for the same services as part of another program.
  - Double Counting not permitted in PJM markets; resources cannot be compensation for the same MWs/services in retail and wholesale

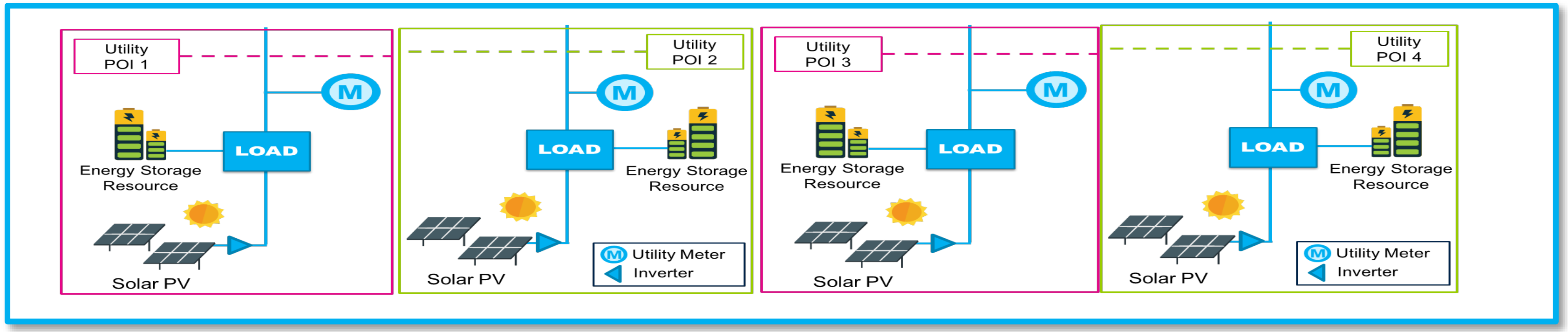
- **Retail Net-Energy Metering (NEM)** : DER Resources modeled at a location with a NEM rate and wanted to participate in wholesale markets through a DERA.
  - Participation in wholesale market will need to be approved by EDC after evaluation of resource(s) participation in NEM program and the associated revenue for that participation
    - The will be implemented in the Utility Review process, and will be on a utility-by-utility bases to capture different utility NEM requirements
    - Example: an “all in” NEM rate that already compensates for capacity and ancillary services will not be able to participate in PJM Markets without double counting. NEM rates that are “energy only” may allow resource(s) to participate in PJM Markets.

- NEM Use Case 1: Solar resource(s) participating in NEM programs



Determination needed by EDC if Solar resource can participate in PJM Markets without double counting

- NEM Use Case 2: Solar resource(s) participating in NEM programs with co-located ESR



Determination of solar participation (use case 1) and if ESR can participate in PJM Markets and necessary metering

Double Counting

- **Wholesale / Retail Market Coordination**: An example of this scenario would be Flagging for normal DR activity while Peak-shaving for Capacity. Any such activity would need to be monitored and flagged.
  - For situations such as the example above, resources would be scheduled for retail, and they would not be paid for wholesale.

- **Wholesale service (such as front of the meter generation) and distribution service being run at the same time**: In this scenario, a resource is dispatched by PJM for distribution level services, therefore, they are self-scheduled for energy in the PJM Market. An example of such would be a battery that is running on-peak.
  - If the resource is dispatched, it must reflect this in their wholesale market offer.

Use Cases

- Use Cases being developed and worked in PJM DIRS
  - Details of use cases are not covered in proposal but will continued to be worked and updated through the DIRS

PJM continues to welcomes proposals from stakeholders on how different DERA use cases and proposal areas that need to be detailed for each use case.

Purpose of Use Cases

- Stress test the DERA model
- Build understanding by filling in details
- Cohesive examples to use throughout compliance process
- Highlight technology-specific needs
- Ability to iterate and introduce alternatives

Use Case Characteristics

Composition	Whether multiple technologies and/or resource types exist within the DERA Homogenous: only one type is present Heterogeneous: multiple types are present
Configuration	Relation of the DER physical elements to retail load Front of the meter: not co-located with retail load Behind the meter: co-located with retail load
Resource Type	Specifies type of market participation Distributed Generation Resource (DGR): state interconnected generator Demand Response (DR): activity used to reduce load Energy Efficiency (EE)
Technology Types	Type of generation or load reduction in DERA DGR: Solar, Wind, ESR, diesel, electric vehicle w/ V2G, etc. DR: On-site load reduction, On-site generation for retail load reduction
Market Participation	All market services the DERA is technically capable of providing
Sites	Number of unique sites and relevant registration and modeling information
Tx Location	PJM node(s) to which an aggregate maps and how DERA will be priced

Use Cases Outlined To-Date

	Composition	Configuration	Technology Types	Market Participation	Sites	Tx Location	Demonstration Goals
1	Homogeneous	Front of the meter	Solar	Cap, En, An	One	Single Primary Node	• Demonstrate size requirements and their implications.
2	Heterogeneous	Front of the meter	Solar + ESR	Cap, En, An	Multiple	Single Primary Node	• Demonstrate how information is exchanged on an aggregate basis. • Highlight any impact to the utility review given multiple distribution feeders
3	Homogeneous	Behind the meter	ESR	Cap, En, An	One	Single Primary Node	• Demonstrate how ESR participates as behind the meter generation with injections in DERA
4	Heterogeneous	Behind the meter	DR + ESR	Cap, En, An	One	Single Primary Node	• Illustrate heterogeneous aggregates with a DR component, Illustrate ESR model within an aggregate.
5	Heterogeneous	Behind the meter	DR + Solar	Cap, En, An	One	Single Primary Node	• Illustrate a NEM component and its implications.
6	Heterogeneous	Behind the meter	Solar + ESR	Cap, En, An	Multiple	Single Primary Node	• Illustrate a multi-site residential aggregation where hybrid solar-storage is in place. • Illustrate a NEM component and its implications, particularly multi-site.

Coordination	
DER Registration	• Utility Review Process • 60 Day timeframe for review • Addresses necessary review, data submissions and studies required
Modification of List of Resources	• Adding or Removing resources from a DERA will require a re-review of the aggregation for market participation • 60 Day timeframe for review
EDC Coordination	• Communications necessary for safety and reliability of the transmission and distribution systems • Overrides

EDC Coordination

Interconnection → Registration/ Utility Review → Operations → Settlement & Compliance

Utility/State Process

PJM Order 2222 Framework

- Interconnection
- Registration/Utility Review
- Operations
- Settlement & Compliance

Resources will go through their applicable state interconnection process prior to entering the PJM registration process

- Valid State IA will be needed for each underlying DER to operate as part of a DERA
- DERs will be required to follow all requirements within State IA
- Likely some exceptions for a valid State IA for Planned DER offering into forward capacity auctions
  - Interconnection agreements would still need to be in place prior to delivery year and DERA going operational

- Interconnection
- Registration/Utility Review
  - Timeline
  - Data Requirements
  - Modification of resources within a DERA
- Operations
- Settlement & Compliance

- Electric Distributor definition:
  - a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Key EDC responsibilities for 2222

- Review and approve DERA participation in the wholesale market
  - Ensure participation does not create safety and reliability issues on the distribution system
  - Participation complies with RERRA “small” EDC process
    - Participation is only allowed if there is an effective order, ordinance or resolution
  - Assist with the review and collection of certain data

Registration review time line

- Registrations submitted by DER Service Provider (DERSP) after resource goes through utility interconnection process
- EDC has 60 days to review and approve the registration
  - If the registration is denied and DERSP resubmits, then EDC has 15 business days to review
    - Denied registrations must indicate specific reason for denial
  - If EDC denies and DERSP disputes then there is 60 days to resolve between PJM, EDC and DERSP.
  - Registration outcome if no action from EDC before deadline
    - Small EDC will auto deny
    - Large EDC will auto approve
- PJM has 10 business days for final registration approval
  - Auto-confirm unless EDC has reliability concerns

Registration Information (work in progress)

Data	Notes	DERSP	EDC	PJM
Max Load (kW)	Max hourly load over prior 12 months	Submits	approve/deny	review
Max Injection (kW)	Max injection amount based on interconnection process	Submits	approve/deny	review
Max Market Eligibility	Maximum amount that will be offered in the market	Submits	review	review
Load Reduction Method	If DR or RBTMGwDI related then indicate load reduction capability (kw) for each load reduction capability (HVAC, Refrigeration, Generation, Lighting, Industrial Process, etc.)			
Generator Details	For each Generator indicate the technology (battery, solar, CT, etc.), nameplate capacity, inverter type, installation date, ride through capability enabled, voltage control enabled and other details.	Submits	review	review
EDC Interconnection ID	Reference to approved EDC interconnection	Submits	approve/deny	review
Retail Agreements	NEM, PURPA, etc.	Submits	approve/deny	review
Peak Load Contribution (PLC)	Used to determine capacity nomination for DR related DER	Submits	approve/deny	review
Loss Factor		Submits	approve/deny	review
EDC reliability issue	EDC provides input to PJM if DER should not be allowed to participate because it will create a reliability issues for Distribution System	review	submits	approve/deny

Expect to leverage functionality similar to DR registrations in DR Hub

Registration Information (continued)

Data	Notes	DERSP	EDC	PJM
Registration Start/End date		Submits	review	review
Registration Status		Submits	review	review
DER type	Distributed Gen (DG), DR, DRwDI (distribution injection), RBTMGwDI (retail BTMG where only the distribution injection will participate in wholesale market), EE			
Transmission Zone		Submits	approve/deny	review
EDC		Submits	approve/deny	review
LSE	load serving entity - work in progress, may only need for negative dec in energy market			
Market	DA/RT Energy, Capacity, SR, Regulation	Submits	review	approve/deny
Expected participation hours	Hours when DER is expected to participate - allows EDC to know when resource is expected to be in the market	Submits	review	review
PJM Telemetry setup	Reference to telemetry code for SCADA link	Submits	review	approve/deny
EDC account number	EDC specific reference, more than one DER or same type may be aggregated at same pnode on one registration	Submits	approve/deny	review
Physical address for DER		Submits	approve/deny	review
EDC Interval Meter	Indicate if EDC meter or other meter used for settlements	Submits	approve/deny	review
RERRA Evidence	Small EDC reference to RERRA that allows participation	Submits	approve/deny	review
Energy Pricing Point - pnode	Expect that PJM will create default based on zip code and EDC will review and update (focus on larger DER). One resource may be mapped to more than 1 pnode.	review	submits/updates - approve/deny	submits

Expect to leverage functionality similar to DR registrations (DR Hub)

Use Case 1: Solar attached to distribution system approved through utility interconnection process

NEM, PURPA or other retail agreement that impacts participation

Registration Info							Resource Info											
Registration Start/End date	DER type	Transmission Zone	EDC	Market	Expected participation hours	Resource Name	EDC account number	Physical address for DER	Energy Pricing Point - pnode	Max Load (kW)	Max Injection (kW)	Max Market Eligibility	Load Reduction Method	Generator Details	EDC Interconnection ID	Retail Agreements	EDC reliability issue
6/1/23-5/31/24	DG	PECO	PECO	Capacity, energy	WD, 0800 - 2000	Dawson Solar1	a3049333	12 Maple Street, Dawson, PA	A	0	500	500	na	Solar, etc.	qvd-01	None	No

Plan to have PJM assign a default based on zip code when size < X kW. EDC to review and update.

Use Case 2: Aggregate solar attached to distribution system approved through utility interconnection process

Registration Info							Resource Info											
Registration Start/End date	DER type	Transmission Zone	EDC	Market	Expected participation hours	Resource Name	EDC account number	Physical address for DER	Energy Pricing Point - pnode	Max Load (kW)	Max Injection (kW)	Max Market Eligibility	Load Reduction Method	Generator Details	EDC Interconnection ID	Retail Agreements	EDC reliability issue
6/1/23-5/31/24	DG	PECO	PECO	Capacity, energy	WD, 0800 - 2000	Dawson Solar1	a3049333	12 Maple Street, Dawson, PA	A	0	500	500	na	Solar, etc.	qvd-01	None	No
						Joeville Solar1	t34234234	1 Oak Rd, Joeville, PA	A	0	300	300	na	Solar, etc.	jvg-87	None	No
									Total		800	800					

Max offer amount in the markets

Registration aggregation – same DER type on the registration

Use Case 3: Battery that will provide load reductions and inject to the distribution system approved through utility interconnection process

Registration Info							Resource Info											
Registration Start/End date	DER type	Transmission Zone	EDC	Market	Expected participation hours	Resource Name	EDC account number	Physical address for DER	Energy Pricing Point - pnode	Max Load (kW)	Max Injection (kW)	Max Market Eligibility	Load Reduction Method	Generator Details	EDC Interconnection ID	Retail Agreements	EDC reliability issue
6/1/23-5/31/24	DRwDI	PECO	PECO	Reg	7X24	Acme	a3049333	12 Ash Street, Jones, PA	B	400	400	400	Gen	Battery, Ride through, etc.	tr-0009	None	No

Will only participate in the Regulation market

Registration will indicate market eligibility

Use Case 4: Industrial customer with load reduction capability and generation approved through utility interconnection process

EDC visibility for injection reason

Registration Info							Resource Info											
Registration Start/End date	DER type	Transmission Zone	EDC	Market	Expected participation hours	Resource Name	EDC account number	Physical address for DER	Energy Pricing Point - pnode	Max Load (kW)	Max Injection (kW)	Max Market Eligibility	Load Reduction Method	Generator Details	EDC Interconnection ID	Retail Agreements	EDC reliability issue
6/1/23-5/31/24	DRwDI	PECO	PECO	Capacity Energy, SR	7X24	Metal Fabrication	a3049333	12 Ash Street, Jones, PA	B	300	200	500	Gen - 200, Process - 300	Diesel, etc.	tr-0009	None	No

Illustration – expect to model as 1 resource but need to work out market specific details

Use Case 5: Home with solar and battery approved through utility interconnection process

Registration Info							Resource Info											
Registration Start/End date	DER type	Transmission Zone	EDC	Market	Expected participation hours	Resource Name	EDC account number	Physical address for DER	Energy Pricing Point - pnode	Max Load (kW)	Max Injection (kW)	Max Market Eligibility	Load Reduction Method	Generator Details	EDC Interconnection ID	Retail Agreements	EDC reliability issue
6/1/23-5/31/24	RBTMGwDI	PECO	PECO	Energy, Reg	0800-2000	Joe's house	a3049333	12 Ash Street, Jones, PA	B	5	2	2	Gen: 7 kw	Solar 5 kwh, battery 2 kw	tr-0009	None	No

Only injection participate in wholesale energy and regulation market

Agreement type will impact wholesale market participation options

From Order 2222…

- Each RTO/ISO to revise its tariff to specify that distributed energy resource aggregators must update their lists of distributed energy resources in each aggregation (i.e., reflect additions and subtractions from the list) and any associated information and data.
  - Distributed energy resource aggregators will not be required to re-register or re-qualify the entire distributed energy resource aggregation.
  - The impacts of modifications may often be minimal, an abbreviated review process should be sufficient for the distribution utility to identify the cases where an addition to the list of resources might pose a safety or reliability concern.
  - Could occasionally indicate changes that justify restudy of the full distributed energy resource aggregation

- Aggregators that are modifying an existing DERA will need to submit modifications to the utility review process
- Adding/Removing a DER to a DERA
  - 60 days review process; same review process as origination on DERA which is still an abbreviated process in comparison to generation changes
  - If DERA is part of a DERA CP resource, these aggregations will be active for the full delivery year and will not be able to be modified.
  - DERA changes can be made on a quarterly basis to all any potential updates to be reflected into PJM models.

- Interconnection
- Registration/Utility Review
- Operations
  - Terminology/Overview
  - Operations Coordination (Day Ahead and Real-time)
  - Utility Overrides
  - Communication
- Settlement & Compliance

- Bid parameter updates
  - Updates to the full dispatchable economic range for an aggregation to operate reliably
  - Updated any time from before day ahead through real-time
  - Eco Min/Max
- Real-time override
  - A utility override of a PJM dispatch signal to DERA
  - Utility can determine the method of how this is achieved

- Each EDC has its own reliability criteria
  - These are not determined by PJM, nor monitored or controlled by PJM.
  - Planned system conditions requiring updated bid parameters should be coordinated in advance.
  - Need for updated real-time bid parameters or overrides to maintain reliability can be the result of (but not limited to) unplanned outages, safety, or load beyond forecasted expectations.
  - Real-time overrides are expected to be abnormal and are tracked. Routine overrides may result in re-evaluating market participation levels.
  - EDC maintains sole responsibility for the reliable operation of the distribution system at all times and always maintains authority to override PJM's market dispatch.

3 Timeframes for EDC Updates & Overrides

1. **Registration / Utility Review Process**: Prior to approving an aggregation for market participation, EDCs review and approve a dispatchable range for the proposed aggregation.
   – Aggregations submitting ranges the EDC cannot reliably expose to PJM on a "normal" basis should be denied (or modified).
2. **Day-Ahead:** Prior to day-ahead submittal, EDCs and Aggregators should coordinate an agreed upon range of MW dispatch per hour for DERA to submit to market.
   – MW levels impermissible by the EDC shall not be submitted in ECOMIN/ECOMAX.
3. **Real-Time:** For reliability concerns, any action the EDC deems necessary shall be executed by the aggregate.
   – EDCs should provide explanation after the fact as to the reliability concern and need to override for both PJM and the Aggregator.
   – This transparency will be useful for understanding potential persistent issues with an aggregation's operations.

Note: DERAs are not eligible for LOC or PAI excusals due to EDC override and will be subject to any applicable deviation changes / penalties.

- EDC should coordinate with aggregator on planned maintenance and other distribution work that will impact dispatchability of DER/DERA prior to day-ahead to allow aggregator to accurately reflect DERA capability in the market.
- PJM expects economic parameters from the aggregator to be in the form of a dispatchable range verified by the EDC prior to submittal.
- Ideally, day-ahead bid parameters will match those in real-time

- PJM expects to dispatch an aggregation within it's agreed upon range (ecomin to ecomax), based on PJM system needs and economic dispatch, unless there is an EDC declared condition for an override.
  - If an override is required by the EDC, the aggregator shall follow EDC dispatch direction and update their economic parameters accordingly in PJM Markets
  - PJM markets and pricing will react based on the aggregation's submitted parameters
- The EDC can require additional controls for distribution reliability within the local interconnection process (override: registration).

Operations Coordination

Day Ahead bid parameter update

Prior to Day Ahead Run (11:00)

- **EDC** – Notify Aggregator of any Ops Limitations
- **DERA** – Submits Market Bids to PJM
- **PJM** – Clears DERA based on updated bid-in parameters

After Day Ahead Run (13:30)

- **PJM** – Provide Aggregator and Utility (TBD) with DA schedule
- **EDC** – Receives DA Schedule (TBD)
- **DERA** – Receives DA Schedule

Re-Bid and Intraday (14:15)

- **DERA** – Provide updates to allowable parameters to PJM
- **PJM** – Receives parameters, dispatches based on updated parameters, and communicates response
- **EDC** – Submits any pre-dispatch bid parameter updates for unplanned outages and/or transfers.

Real-time bid parameter update

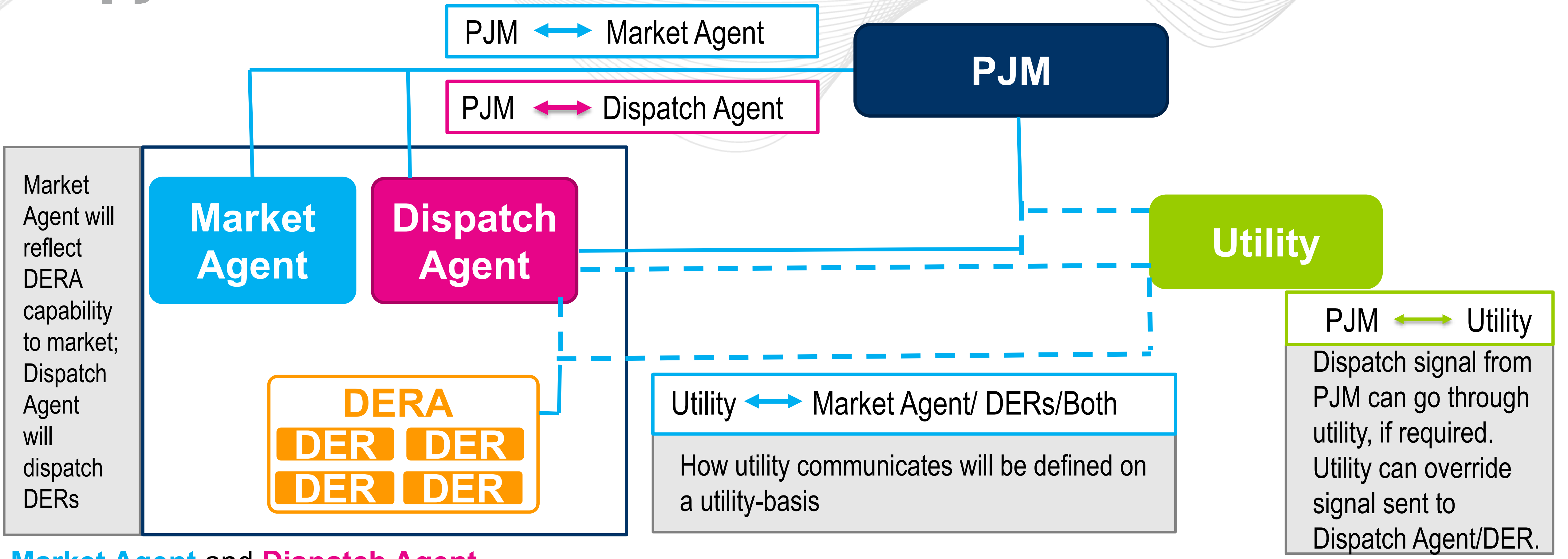
DER Dispatch

- **DER DISPATCHER** – Executes require dispatch through DER telemetry
- **PJM** – Receives dispatch confirmation
- **EDC / DERA** – Receives dispatch confirmation
- **EDC** – Submits or executes any post-dispatch overrides for unplanned outages and/or transfers.

Real-time override

Updates to bid parameters should be done prior to Day Ahead, when possible. Bid parameters shall be updated in real-time, as needed, especially if an override to dispatch instructions for unplanned outages or reliability is required.

Real-Time Communication



Market Agent and **Dispatch Agent** could be DER Aggregator, Utility, or 3rd party as agreed in registration process

⟷ Communication ▬ Required Communication ▬ ▬ Utility Communication

- Interconnection
- Registration/Utility Review
- Operations
- Settlement & Compliance

- PJM will need to define communication and data requirements to ensure proper settlements addressing both retail and wholesale billing
  - Will need to continue discussion at EDC coordination workshops and DIRS to identify use cases and needs.

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