

Transition Cycle 2, Phase I System Impact Study Results

FAQs for Developers

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General Questions

Q1 *Who is impacted by these Transition Cycle 2 (TC2), Phase I study results?*

A1 Transition Cycle 2 projects are all New Service Requests in the AG2-AH1 queues that did not yet receive a Final Agreement, as well as the final selection of Resource Reliability Initiative (RRI) projects. The AG2-AH1 projects entered the PJM interconnection process in the October 2020 through March 2021 time frame. Summer peak, winter peak and light load steady state load flow analyses were performed for the AG2-AH1 projects that make up Transition Cycle 2. The Phase I System Impact Study summarizes the results of these studies and provides cost allocation for any required Network Upgrades to accommodate the new interconnection.

The Interconnection timeline is posted on the [PJM.com Planning page](#).

Q2 *What does the System Impact Study (SIS) tell me?*

A2 The Phase I, Phase II and Phase III System Impact Studies are a regional analysis of the effect of adding New Service Requests to the Transmission System and include an evaluation of the New Service Requests' impact on deliverability to the aggregate of PJM Network Load.

- For the Phase I System Impact Study, PJM studies each New Service Request on a summer peak, winter peak and light load RTEP base case. PJM will only perform load flow analysis during the Phase I System Impact Study.
- The Phase I SIS results show both: 1) the magnitude estimated scope, cost and elapsed schedule to complete the required physical interconnection work and 2) the magnitude scope, cost and elapsed schedule to complete any Network Upgrade work to accommodate the interconnection and to address any reliability criteria violations on the grid identified by the analysis performed during Phase I SIS.
- Procedures and other terms related to the three study phases are outlined in Tariff, Part VII, Subpart D, sections 307, 308, 310 and 312 and Tariff Part VIII, Subpart C, sections 404, 405, 407 and 409. See PJM Manual 14H, Section 4.2.1 for more details on what the System Impact Study provides.

Q3 *Where can I find the definitions of terms used for the Cycle study approaches?*

A3 Refer to [Tariff Part VII, Subpart A, section 300](#).

Q4 *What if I have a question about my SIS report results?*

A4 Please review this FAQ document prior to contacting your PJM project manager with any project-specific questions. If you still have any general questions regarding TC2 Phase I SIS or TC2 Decision Point I (DP1) after reviewing the FAQ, please contact InterconnectionSupport@pjm.com.

Phase I Model Questions

Q5 *What RTEP series base case was used for the TC2 Phase I models, and what upgrades are modeled?*

A5 The TC2 Phase I models are based on the 2024 RTEP series models with updates in topology to reflect a 2028 base case year. The 2023 series load forecast for a 2028 Delivery Year from the 2023 series Window 2 models was used for the TC2 Phase I models. During the initial TC2 base case development in July of 2024, all PJM Board-approved baseline, supplemental and securitized Network Upgrades were included in the model if the projected in-service date of the upgrade was on or before the seasonal case reference cutoff dates as outlined in Manual 14B, Section C.3.1.3.

Q6 *Were any Network Upgrades modeled in the TC2 Phase I models for TC1 and prior queues?*

A6 The same rules apply as outlined in the previous question (Question 5). When the TC2 base case was developed in July of 2024, only securitized Network Upgrades were modeled for prior Cycles/queues if the upgrades were securitized, PJM Board approved and had a projected in-service date by the reference year cutoff dates outlined in Manual 14B. For the securitized upgrades that are not modeled in the TC2 Phase I models, they were considered in the analysis as potential mitigations and tested (as required) to determine if the upgrade is a suitable mitigation required for the TC2 Cycle. For reference, a securitized Network Upgrade is a Network Upgrade that has been fully funded by a prior Cycle or prior New Service Request under the old interconnection process.

Q7 *Did PJM take any Board-approved upgrades that were not included in the TC2 Phase I Cycle models into consideration for the TC2 Phase I analysis?*

A7 Yes, PJM did consider PJM Board-approved upgrades (baseline, supplemental, securitized network) that were not included in the TC2 Phase I Cycle model as potential mitigations in the studies and completed testing (as required) to determine if the upgrade(s) was a suitable mitigation required for the TC2 Cycle. While the TC2 New Service Requests may take advantage of the approved upgrades if they are determined to be suitable mitigations, an interim deliverability study may be required for any generators contingent on the upgrade(s) and planning to come into service prior to the upgrade(s) being completed.

Q8 *For New Service Requests that share a common Point of Interconnection (POI) on a FERC jurisdictional facility, will they be aggregated in the TC2 Phase I models?*

A8 No, New Service Requests will continue to be modeled separately in order to determine their individual project contributions (megawatt impacts) to facility overloads in the GenDeliv and Individual Plant Deliverability (IPD) studies. For New Service Requests sharing a common POI, PJM will aggregate the megawatt impact of the New Service Requests to determine if the aggregated impact meets cost allocation criteria as outlined in Attachment B of Manual 14H. If the aggregated impact meets cost allocation criteria, then cost allocation will be applied proportional to the megawatt impact of each individual New Service Request. This is consistent with how project aggregation was handled for TC1 Phase II and III.

Please see [additional educational material](#) (PDF) on this topic.

Q9 Why do some units/New Service Requests have different Pmax values across the different seasonal cases?

A9 In line with Manual 14B, Attachment C, a unit's Pmax value in each seasonal case should align with its maximum seasonal net energy output. Typically, the unit Pmax values in the summer peak and light load cases will be identical, with an exception for winter peak where conventional units, such as combustion turbines, combined cycle plants and nuclear plants, will have higher Pmax values to reflect the higher winter energy output.

There are also some scenarios, depending on the type of TC2 New Service Requests under study, where the generator Pmax/Pmin may not match across seasons if the New Service Request is claiming Capacity Interconnection Rights (CIRs) from an existing resource at the same POI. In these modeling scenarios, PJM will model the incremental output above the resource's claimed CIRs already existing in the case based on the resource's seasonal ramping.

Battery Storage Projects: As it relates to battery projects that charge from the grid and are claiming CIRs from an existing resource at the same POI, the Pmin value in light load must reflect -100% of the megawatt energy (MWE) to capture the charging impact during the light load studies.

CIR Transfers: Also, the Pmax/Pmin differences between seasons will not apply to TC2 New Service Requests that are claiming CIRs from an existing resource located at a different POI. These CIR claims are considered POI transfers, and therefore the full output of the New Service Request will be modeled at its final POI location in the Phase I models to support a POI transfer study completed later in each phase of the TC2 studies. A comparative generator deliverability analysis with the claimed megawatts at the original deactivated unit's POI will be performed to analyze any change in flowgate loading to determine overload and cost responsibilities for the New Service Request claiming the CIRs.

Q10 Why are some New Service Requests modeled in some of the seasonal cases but missing from the other cases?

A10 This scenario typically only applies to: 1) New Service Requests claiming CIRs at the same POI as the deactivated resource and 2) New Service Requests that are only requesting a seasonal-based uprate. For the New Service Requests claiming CIRs at the same POI as the deactivated resource(s), there may be no need to model any incremental output above the existing CIRs already modeled in the case depending on the seasonal resource ramping. For New Service Requests that are only requesting a seasonal-based uprate, such as thermal units looking to increase CIRs and summer net energy, there may be no change to the existing winter net energy output and therefore no need to model the uprate project in the winter peak case.

Q11 How is the block dispatch being set in each seasonal case?

A11 Please reference Manual 14B, Attachment C, Section C.3.1.3, Step 2 for more details on the procedure used to set the block dispatch in the RTEP base case. PJM will dispatch blocks 1, 2 and 3 generation consecutively based on demands of the system while also leveraging TARA SCED to ensure generation is ramped as required for constraint control while also meeting CETO requirements by designated area. Typically blocks 1–3 are required for summer and winter peak cases, while only blocks 1–2 may be required for the light load case.

Q12 How were the generator output/performance values established for the TC2 models?

A12 In the TC2 Phase I models, the generator EEFORd class averages, renewable resource capacity factors (CF), and renewable resource ramp limits in the GD (GenDeliv) datafiles are all based on the 2024 RTEP series values. The renewable CF and ramp limits are developed on an annual basis and posted as part of the study assumptions for the given RTEP series. For reference, the 2024 RTEP series renewable CF and ramp limits values by season may be found on slides 16–18 in the [Review of 2024 RTEP Assumptions TEAC presentation](#) (PDF).

Typically for non-solar/wind units, the 50/50 and regular adder ramp limits should be the same across RTEP years where the 50/50 limit is set to 100% across all seasons and the adder ramp limit is set to 1 – PJM Avg EEFORd (~94%) for summer peak only. There is no regular adder ramping in the winter peak or light load studies.

Existing unit CIRs were also updated to reflect the latest 2030 CIR values provided by Resource Adequacy Planning to better reflect recent generator testing performance.

System Impact Study (SIS) Analysis Questions

Q13 What is the study approach for Transition Cycle 2 projects?

A13 Transition Cycle 2 projects were studied under the Cycle study process approved as part of PJM's interconnection process reform. The Cycle study process is to evaluate Transition Cycle 2 projects using the reformed GD process as outlined in Manual 14B, Attachment C, including the Individual Plant Deliverability (IPD) test.

PowerGem is releasing PJM GD Reform 2503 on Oct. 31, 2025, which addressed issues running TARA using the light load sub file and contains additional IPD test corrections for analysis on CIR only updates. Please use this latest version of the PJM GD Reform 2503 for running analysis on the TC2 Phase 1 case.

More information about the GD2 reform implementation for TC2 can be found in the [Transition Cycle 2 Phase I Model Posting FAQs for Developers](#) (PDF).

Transition Cycle 2 projects were cost allocated under the Cycle-based cost allocation rules in Manual 14H, Attachment B.

Q14 The terms “Cluster study” and “Cycle study” seem to be used interchangeably. What is the difference between a “Cluster study” and “Cycle study”?

A14 A “Cycle study” refers to the study approach used for a group of New Service Requests (i.e., Cycle) approved as part of PJM's interconnection process reform, whereas a “Cluster study” refers to the stability study approach of grouping a subset of New Service Requests within a Cycle into a cluster based on their electrical proximity to be studied together.

Q15 *If I am in Transition Cycle 2 and my Phase I study runs clean, can I accelerate to a final agreement?*

A15 New Service Requests that are eligible to accelerate to final agreement at DP1 per PJM Tariff Part VII, Subpart D, section 309 (A)(2) have received an email notification on Oct. 3, 2025, from their PJM project manager regarding the next steps for their project. A New Service Request that does not have any cost allocation may still be blocked from accelerating; refer to Question 19 below. For more details on acceleration eligibility at DP1, see PJM Manual 14H, Section 4.4.3.

Q16 *My project's System Impact Study (SIS) report only provides the final Cycle loading for each overloaded flowgate. Why is the pre-Cycle loading not provided?*

A16 In the new Cycle study process, pre-Cycle loading is no longer a concept or part of the study results (e.g., there is no serial first to cause/driver and there is no queued/serial project order within any given Cycle under study). The final Cycle facility loading (MVA to mitigate) is the responsibility of the Cycle under study (with Cycle project contributors) if the facility loading is not already mitigated by a pre-existing upgrade (e.g., Prior Queue/Cycle upgrades and RTEP baseline/supplemental upgrades).

- The final facility loading results for each Cycle are contained within that Cycle and the base case year assumptions for that Cycle's model.
- Please refer to PJM Tariff Part VII, Subpart D, section 307 A.5.C, PJM Tariff Part VIII, Subpart C, section 404 A.5.c and PJM Manual 14H, Section 4.2.6-3, first sub-bullet.

Q17 *There is a withdrawn project contributing to an overloaded facility that my project also contributes to. Why wasn't this withdrawn project removed for the Phase I analysis?*

A17 The TC2 Phase I study officially commenced on July 7, 2025. The Phase I model was locked on this date for the Phase I analysis. The study results to be delivered prior to the start of Decision Point I will be based on the July 7 study model. Any changes to projects in prior queues/Cycles after the model lock date will be captured in model updates for the Phase II studies along with the outcome of any changes to TC2 projects during Decision Point I.

Q18 *Did Transmission Owners perform analysis of lower-voltage facilities for Transition Cycle 2, Phase I?*

A18 Yes, a Transmission Owner analysis, including an analysis of lower-voltage facilities, was performed as part of the Transition Cycle 2 Phase I study process and will be retooled in subsequent phases.

Q19 *My project doesn't have any cost allocation for system reliability Network Upgrades or any contingent upgrades identified in the System Impact Study report. Why are system reliability upgrades still listed in my report?*

A19 Although your project may not have cost allocation or any contingent upgrades required for overloaded flowgates listed in your System Impact Study report, your project may fall into the potential aggregate contributor pool. Projects in this pool may receive cost allocation in later phases of the Cycle study based on changes to New Service Request projects, and therefore these upgrades will be listed until the upgrades are securitized (or drop away

as a required upgrade based on changes in the study results). A securitized Network Upgrade is a Network Upgrade that has been fully funded by a prior Cycle or prior New Service Request under the old interconnection process. Please refer to PJM Manual 14H, Section B.3.1 for cost allocation eligibility criteria.

Q20 *Do the TC2 study results also consider recent system network changes, such as rating increases, substation reconfigurations, etc.?*

A20 Yes, as part of the PJM analysis and review with the Transmission Owners, any current known rating increases and contingency changes as the result of in-service system reconfigurations are considered before assigning any system reinforcements for a TC2 reliability criteria violation.

Q21 *When should I expect to see the next set of study results for my project?*

A21 Project Developers with Transition Cycle 2 projects (that meet the DP1 requirements to move on in the Cycle) can anticipate seeing the Phase II System Impact Study results posted on PJM.com around the end of April 2026. Please reference the Interconnection timeline on the [PJM.com Planning page](#).

PJM will prepare the TC2 Phase II model considering system updates and changes from DP1. PJM will post the TC2 Phase II model once it is locked and ready for the Phase II SIS analysis. Summer, light load and winter peak analysis cases will be made available.

PJM will make an announcement prior to the release of the Transition Cycle 2 Phase II study results and the beginning of Decision Point II.

Retooled load flow analysis, along with stability and short circuit analyses, will be performed in Phase II, and results will be shared in the Phase II SIS report. Facilities Study results for physical interconnection scope of work will also be provided with the Phase II SIS report.

Q22 *My project has a battery component. How can I determine whether my project is injecting (i.e., generating) or withdrawing (i.e., charging) for a given flowgate?*

A22 For TC2 Phase I, battery charging is considered only for light load analysis and not for summer peak or winter peak. In the flowgate details for light load analysis, if the project was dispatched as withdrawing (i.e., charging) for a given flowgate, there will be a battery icon representing “Charging” in the “Type” column of the FG details.

Q23 *Does the Phase I analysis include the impact of topology-changing reinforcements such as recently approved baseline projects?*

A23 As described in Question 7 above, all PJM Board-approved upgrades (baseline, supplemental, network) that were not included in the TC2 Phase I base model were considered in the Phase I analysis as potential mitigations and tested (as required) to determine if the upgrade is a suitable mitigation required for the TC2 Cycle. However, running a full topology-changing reinforcement sensitivity study to identify eliminated reinforcements (as was done in TC1 Phase II and Phase III) is not completed during the Phase I studies.

TC2 Phase II analysis is anticipated to include full sensitivity analysis on all selected topology-changing reinforcements (including both Board-approved upgrades and additional proposed network upgrades as appropriate) to identify eliminated reinforcements.

Affected System Study (AFS) Questions

Q24 *What do the different statuses mean under “Affected System – PJM Identified Violations” and “Affected System – Non-PJM Identified Violation”?*

A24 PJM consistently coordinates with other Affected System Operators regarding new Interconnection Service Requests to determine potential impacts on neighboring systems. The affected system study process is performed in two stages.

The initial stage involves PJM evaluating the New Service Request to identify any potential impact on tie-line facilities that connect PJM to another affected system entity, based on PJM's planning analysis criteria. A project status of “Impact Identified” for an applicable Transmission Provider signifies a potential impact on a tie-line facility identified through PJM's analysis. Conversely, a “No Impact” status indicates that PJM's analysis did not identify any tie-line facility overload.

In the second stage, PJM receives the affected system study screening results from the Affected System Operator. If the Affected System Operator identifies potential overloads, PJM sets the status for that operator under the “Affected System – Non-PJM Identified Violation” section as “Pending.” Other Affected System Operators will be assigned a “Not Required” status. The “Pending” status will be maintained in each Phase SIS report until an official Affected System Study Report is received from the Affected System Operator. Following receipt of the report, the status will change from “Pending” to either “Impact Identified” or “Not Required,” depending on the results.

Q25 *What is the next step for a Project Developer if my report shows a “Study Pending” or “Impact Identified” affected system status?*

A25 If a project has an “Impact Identified” status under “Affected System – PJM Identified Violation,” there is no required action for the Project Developer at this point. Project responsibilities are subject to change, and the developer should await the Phase II and Phase III System Impact Study reports for further information.

“Pending” Status Non-MISO (Action Needed): However, if a project has a “Pending” status for any of the Affected System Operators under “Affected System – Non-PJM Identified Violation,” the Project Developer is required to review the Affected System Operator's Tariff and adhere to all applicable rules for the Affected System Study. It is important to note that all of the Affected System Operators except for MISO require an Affected System Study Agreement to be executed between the Project Developer and the Affected System Operator. If this agreement is not executed within the timeline outlined in the Affected System Operator Tariff/Manuals, the project will not be able to present evidence of executed Affected System Study Agreement to PJM by the end of Decision Point II; therefore, in accordance with PJM Tariff Part VII, Subpart G, section 336, paragraph A.1.d, the project shall be terminated and withdrawn from the Cycle.

“Pending” Status MISO (No Action Needed): Projects with a “Pending” status for MISO under the “Affected System – Non-PJM Identified Violation” section do not require action from the Project Developer until the MISO Affected System Study results are available. The PJM-MISO Joint Operating Agreement (JOA) should be consulted for details on developer responsibilities regarding MISO affected system studies.

Q26 When will a Project Developer receive an Affected System Study Report?

A26 Each Affected System Operator has different timelines and rules for performing an affected system study. Project Developers should refer to the specific Affected System Operator's Tariff for detailed information. PJM works in continuous cooperation with Affected System Operators to ensure that study reports are made available, at the latest, before the conclusion of Phase III.

Cost Allocation Questions

Q27 How was my project's cost allocation determined?

A27 For Phase I, PJM performed the generation deliverability and Individual Plant Deliverability (IPD) tests to determine thermal impacts for summer peak, winter peak and light load conditions. Additionally, PJM member Transmission Owners performed an analysis of their lower-voltage systems. PJM's neighboring Affected System Operators have determined which PJM projects require an Affected System Study. If your project was dispatched against an overloaded facility in TC2, then your project is eligible for cost allocation. PJM has applied the new Cycle cost allocation rules defined in Manual 14H, Attachment B.

Cost Allocation Classification: Your project's impact to the facility will be classified in one of three ways: cost allocated, contingent or potential aggregate contributor. See PJM Manual 14H, Attachment B, B.3.1 for criteria defining cost allocated and potential aggregate contributor, and PJM Manual 14H, Section 4.2.3 for more detail on contingent facilities.

Q28 When determining cost allocation for a given Network Upgrade(s), is PJM using the megawatt impact for each project from the worst reportable flowgate against that facility for the given project?

A28 For a load flow violation, a project's cost allocation for a Network Upgrade is based on the project's highest ramped megawatt impact to the flowgate (monitored facility/contingency pair) selected from the highest post-Cycle loading for each analysis season reported against the facility for the given project. For load flow, a flowgate can be identified by either the Generation Deliverability or Individual Plant Deliverability analyses. These impacts are grouped together by season to determine the highest post-Cycle loaded flowgate by season. This methodology accounts for the differences in the fuel based and seasonal ramping of generators dispatched into a flowgate to ensure that the highest ramped megawatt impact is chosen for cost allocation based on the worst loaded flowgate across seasons for a given facility.

If the Network Upgrade addresses multiple facility overloads, the megawatt impact is additive and includes the megawatt impact from the worst overloaded flowgate reported for each facility. This methodology is required because not all projects in a given Cycle may contribute to the same overloaded flowgate for a given facility. This can occur due to topology differences when a given contingency is taken and the generator dispatch is applied for a given flowgate. Ultimately if the project loads into an overload on the facility (monitored element), which requires a system reinforcement, the project is subject to the cost allocation criteria.

Q29 *If my project shares an Interconnection Switchyard (Common Use Upgrade) with another New Service Request project, how will my interconnection costs be calculated?*

A29 If multiple Project Developers request to connect to the same interconnection substation, the Transmission Owner will determine the scope of work to accommodate all the requests at the substation. The cost for the interconnection will be allocated in proportion to the number of required terminations into the substation.

Q30 *My project shares a point of interconnection with another project. How might this impact my cost allocation?*

A30 In accordance with the PJM OATT, Part VII, Subpart D, Section 407 (A)(2)(a)(iii) and PJM Manual 14H, Section 9.9, PJM aggregated the megawatt impacts of New Service Requests sharing the same point of interconnection (POI) for the purpose of screening them against PJM's cost allocation criteria. This aggregation of the megawatt impact for projects sharing the same POI was implemented to prevent subdividing projects from avoiding the cost allocation thresholds and requirements. For thermal impacts, a project's cost allocation will still be based on the individual project's megawatt impact and NOT the aggregated megawatt impact. Please refer to Question 8 above, as well as the [presentation](#) (PDF) given at the March 2025 Interconnection Process Subcommittee.

Readiness Deposit Questions

Q31 *Which costs are subject to Readiness Deposit?*

A31 The costs subject to readiness are dependent on whether the New Service Request is FERC or Non-FERC jurisdictional. For FERC jurisdictional New Service Requests, 1) the physical interconnection work (Transmission Owner build option only) including Stand-Alone Network Upgrades and Network Upgrades, 2) all BES system reliability upgrades and 3) Transmission Owner-identified upgrades on subregional facilities are subject to readiness. For Non-FERC jurisdictional projects, only 1) BES system reliability upgrades and 2) Transmission Owner-identified upgrades on subregional facilities are subject to readiness.

Please refer to the "Cost Summary" section of the SIS report for more information including:

- A cost summary table, specifying which costs for the particular project are subject to readiness
- Definitions for common terms related to costs subject to readiness

Q32 *Do I have to post any additional deposits in Transition Cycle 2?*

A32 Yes, Readiness Deposits 2 and 3 will be required at Decision Points I and II, respectively. Please review both 1) the Readiness Deposit requirements in PJM Manual 14H, Section 6.2 and 2) Decision Point I requirements in PJM Manual 14H, Section 4.4.

Q33 *If I withdraw at Decision Point I which of my deposits are at risk?*

A33 For Transition Cycle 2, Readiness Deposit 1 (RD1) is 50% at risk prior to the close of Decision Point I. After Decision Point I, RD1 is 100% at risk. Additionally, only 10% of the Study Deposit is at risk regardless of actual study costs, and PJM will draw from the refundable portion of the study deposit to cover actual study cost. Therefore, for

Transition Cycle 2, Decision Point I, the money at risk will be the greater of the actual study cost or 10% of your Study Deposit as well as 50% of RD1. Please refer to PJM Manual 14H, Sections 6.2 and 6.3.

Decision Point I (DP1) Questions

General

Q34 *When will Transition Cycle 2, Decision Point I start and end?*

A34 Please refer to the timeline posted on the [PJM.com Planning page](https://www.pjm.com/planning) for Decision Point I start and end dates.

Q35 *What modifications are allowed in Transition Cycle 2 (TC2) at Decision Point I (DP1)?*

A35 The following modifications are allowed:

1. Projects in Transition Cycle 2 (TC2) may reduce Maximum Facility Output (MFO) and/or CIRs up to 100% of the requested amount. Projects reducing MFO may not have CIRs over ELCC limits.

Note: RRI projects may not reduce their MFO and/or CIRs.

2. Projects with multiple fuel types can reduce the MFO/CIRs associated with a fuel type up to 100%. Such projects can remove a fuel type, but megawatts cannot be swapped between fuel types. Projects with only one fuel type may not change their fuel type.

Note: RRI projects may not change their fuel type.

3. Projects can finalize their POI by:

- Moving along the same segment of transmission line as defined by the two nodes of the transmission line in the Phase I base case; or
- Moving the location of the Point of Interconnection to a different breaker position within the same substation, subject to Transmission Owner (TO) review and approval.

4. Projects may modify their initial Site Control package from what was submitted during the Application Phase if the following conditions are met:

- All provided Site Control meets requirements of Tariff, Part VII, Subpart A, section 302 and Tariff, Part VII, Subpart D, section 309; and
- If new parcels are added, additional Site Control provided at DP1 is either physically adjacent to the initial Site, or Project Developer provides 100% of the easement(s) connecting the additional Site to the initial Site.

Note: The Site Control submitted during the Application Phase established the “initial Site” against which the Site Control provided at DP1 will be compared. The Site Control provided at DP1 will then become the initial Site against which the Site Control provided at DP3 will be compared.

See the Site Control section below for more information.

5. Project Developers may update any equipment data at DP1. Any modeling data associated with the requested change must be submitted via the NextGen tool prior to the close of DP1. Any submitted changes must meet PJM Dynamic Model Developer Guidelines, which are posted on the [Application & Forms page](#).

Note: RRI projects may make modifications to their equipment data only if it does not impact the MFO/CIRs of the project.

Q36 *I have made permitted modifications to my project as part of Decision Point I. When will the models be updated and available to reflect this change?*

A36 Modifications permitted at Decision Point I are incorporated into the model for Phase II SIS analysis. The model will be available and posted to the PJM website in the following weeks after Phase II SIS has begun. PJM first needs to complete the deficiency review of the modifications at Decision Point I before posting the model update. The updated Phase II SIS model will be available with a [CEI request](#).

Q37 *Do we still need to post the calculated readiness amount due during Decision Point I as summarized in the Phase I report even though we know of other projects that are expecting to withdraw or modify and possibly remove the need for certain upgrades?*

A37 Yes, each New Service Request must submit the calculated readiness deposit due based on the Phase I analysis regardless of changes in prior Queues/Cycles after the Phase I model lock date and any expected changes with TC2 projects during Decision Point I. The readiness deposit calculations account for prior readiness deposits received and the New Service Request will only be responsible for the readiness deposit due at the Decision Point to meet the total readiness deposit required as outlined in Manual 14H, Section 6.2.

Q38 *As it relates to Output modifications at DP1, can CIRs be transferred between fuel types within a given project/plant?*

A38 No, CIRs may not be transferred between fuel types as requested and studied in the Phase I studies. The existing CIRs associated with each fuel type may be reduced within the allowable DPI modification limits, but they cannot be transferred between fuel types within the same project/plant. Please reference Manual 14H, Section 9.8.5 as it relates to additional requirements for a multi-fuel new service request.

Q39 *Are batteries allowed to change their grid charging characteristics at DP1?*

A39 Yes, battery projects are allowed to change their grid charging characteristic at DP1 only if the battery is changing from “grid charging” to “no grid charging.” Batteries cannot change from “no grid charging” to “grid charging,” as this will be a material increase in output since batteries are ramped to full withdrawal output in the light load studies for a grid charging configuration. Only output reductions, not increases, are permitted at DP1 and DP2.

Q40 *Are solar projects allowed to change their fixed/tracking characteristics at DP1?*

A40 Yes, solar projects are allowed to change their fixed/tracking characteristics at DP1 only if the solar project is changing from “tracking” to “fixed.” This change from “tracking” to “fixed” is allowed since it is essentially a megawatt impact reduction in the PJM GenDeliv studies due to lower ramp limits for fixed solar and is only applicable at DP1 due to allowable equipment changes. If the change is to go from “fixed” to “tracking,” the change will be

rejected since it is a material impact due to higher ramp limits and a higher megawatt impact for tracking solar projects in the PJM GenDeliv studies. Only output reductions, not increases, are permitted at DP1 and DP2.

Q41 *Are there any considerations and/or limitations when reducing the output of my solar or wind project at DP1?*

A41 Yes, solar and wind projects can reduce MFO without a corresponding CIR reduction as long as the maximum CIR request rules are not violated for these resources. The legacy Capacity Factor rules no longer apply due to the new ELCC rules. Please ensure you reference the [latest table](#) (PDF) on the RAG page on PJM.com for the maximum regional CIRs that can be requested for solar and wind projects.

Q42 *Are there any considerations when changing battery stockpile and hour-class at DP1?*

A42 Yes, there are a couple of considerations. First of all, battery storage facilities can change their hour class at Decision Point I or II in the Cycle. However, if the request becomes eligible for higher CIRs, as a result of the updated hour-class, the Project Developer will need to submit an uprate for the incremental CIRs in order to claim the higher CIR value. Please reference Manual 14H, Section 9.8.5 as it relates to additional requirements for a multi-fuel new service request.

Secondly, if a battery stockpile and hour-class are adjusted at DP1 and reduce the maximum eligible CIRs that may be requested for the battery, a corresponding CIR reduction must be made at DP1. Battery project CIR eligibility is equal to stockpile megawatt-hour divided by hour class, and CIRs requested for the battery cannot exceed this CIR eligibility value. Also keep in mind that there are site control considerations with megawatt-hour/acreage requirements. As it relates to the CIRs that may be requested for limited duration resources such as battery storage, please reference [Manual 21B](#) on how many CIRs can be requested for limited duration resources.

Site Control Changes

Note: The Site Control submitted during the Application Phase established the “initial Site” against which the Site Control provided at DP1 will be compared. The Site Control provided at DP1 will then become the initial Site against which the Site Control provided at DP3 will be compared.

Q43 *If I reduce MFO/CIRs can I also reduce the provided Site Control?*

A43 Yes, if a project reduces MFO/CIRs at DP1, it can reduce its Site Control for its Generating Facility Site if all provided Site Control meets the requirements of Tariff, Part VII, Subpart A, section 302 and Tariff, Part VII, Subpart D, section 309, including acreage requirements for the megawatt size and technology of the project.

Q44 *Can I reduce my Site Control at DP1?*

A44 Yes, a Project Developer can reduce Site Control evidence for their Generating Facility Site at DP1 if all provided Site Control meets the requirements of Tariff, Part VII, Subpart A, section 302 and Tariff, Part VII, Subpart D, section 309, including acreage requirements for the megawatt size and technology of the project. Evidence of removed Site Control is not required.

Q45 Can I add Site Control at DP1?

A45 Yes, Site Control can be added for the Generating Facility Site if the following conditions are met:

1. All provided Site Control meets the requirements of Tariff, Part VII, Subpart A, section 302 and Tariff, Part VII, Subpart D, section 309; and
2. Additional Site Control provided at DP1 is either physically adjacent to the initial Site, or Project Developer provides 100% of the easement(s) connecting the additional Site to the initial Site.

Q46 Can I drop Site Control AND add Site Control at DP1 for the Generating Facility Site?

A46 Yes, whereas this was previously not permitted, PJM has updated its Tariff to allow such changes if the following conditions are met:

1. All provided Site Control meets the requirements of Tariff, Part VII, Subpart A, section 302 and Tariff, Part VII, Subpart D, section 309; and
2. Additional Site Control provided at DP1 is either physically adjacent to the initial Site, or Project Developer provides 100% of the easement(s) connecting the additional Site to the initial Site.

Additionally, evidence of removed Site Control is not required.

Q47 What if Site Control provided during the Application Phase is no longer viable due to no fault of the Project Developer, can I drop that Site Control at DP1?

A47 Yes, a Project Developer can reduce Site Control evidence for their Generating Facility Site at DP1 if all provided Site Control meets the requirements of Tariff, Part VII, Subpart A, Section 302 and Tariff, Part VII, Subpart D, section 309, including acreage requirements for the megawatt size and technology of the project. Evidence of Site Control for removed parcels is not required.

Q48 Do I still need to provide Site Control documents that were previously approved?

A48 If a Project Developer is using a Site Control document to meet a Site Control requirement, they must provide it with their DP1 materials, even if they previously submitted it and it was approved. If a Project Developer elects to no longer use a Site Control document for their project, they do not need to include it in their DP1 materials.

Q49 Do I need to show easements at DP1 for non-adjacent parcels submitted during the Application Phase?

A49 No, easement evidence is required for 50% of the path of the Interconnection Facilities between the Generating Facility Site and either the interconnection switchyard boundary or the boundary of TO-owned land, not including Generating Facility Site Control provided during the Application Phase or Decision Point I.

Project Developers do, however, need to show 100% of the easement(s) at DP1 for non-adjacent parcels submitted at DP1.

Q50 How will PJM handle Transmission Owner easements/Transmission Owner-owned land at Decision Point I?

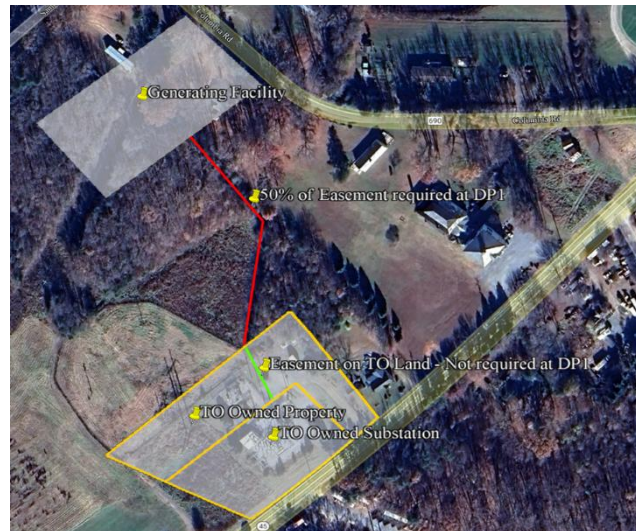
A50 At DP1, Project Developers must provide Site Control for 50% of their Interconnection Facilities from the edge of the project-owned land to either:

- (i) The edge of the TO-owned land (when connecting via an existing TO-owned substation); or
- (ii) The interconnection switchyard (when connecting via a new TO-owned substation).

Note: At Decision Point III, Project Developers must provide Site Control for 100% of the full Interconnection Facilities, including any required TO easements.

Examples

Connecting via an existing TO-owned substation: Project Developer must show Site Control for 50% of the red line.



Connecting via a new TO-owned substation: Project Developer must show Site Control for 50% of the yellow line.



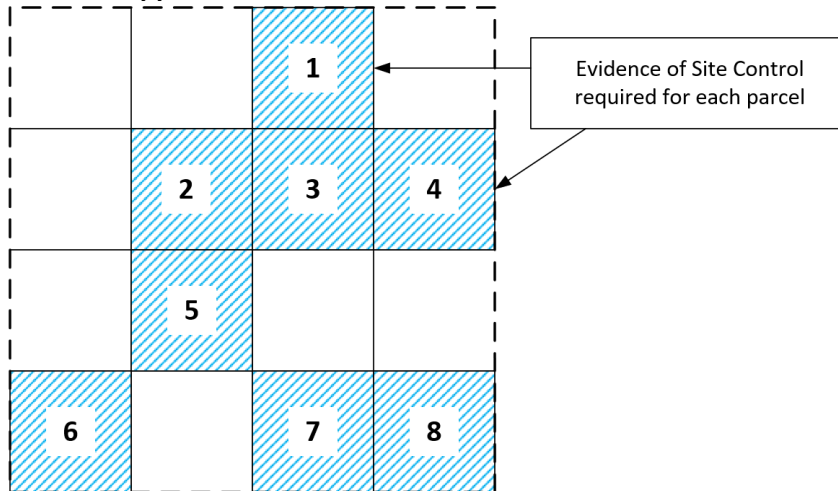
For more information, see the October IPS presentation, 'Transition Cycle 2, Decision Point I Requirements'.

Q51 Can you show examples of Site Control updates that would and would not be accepted?

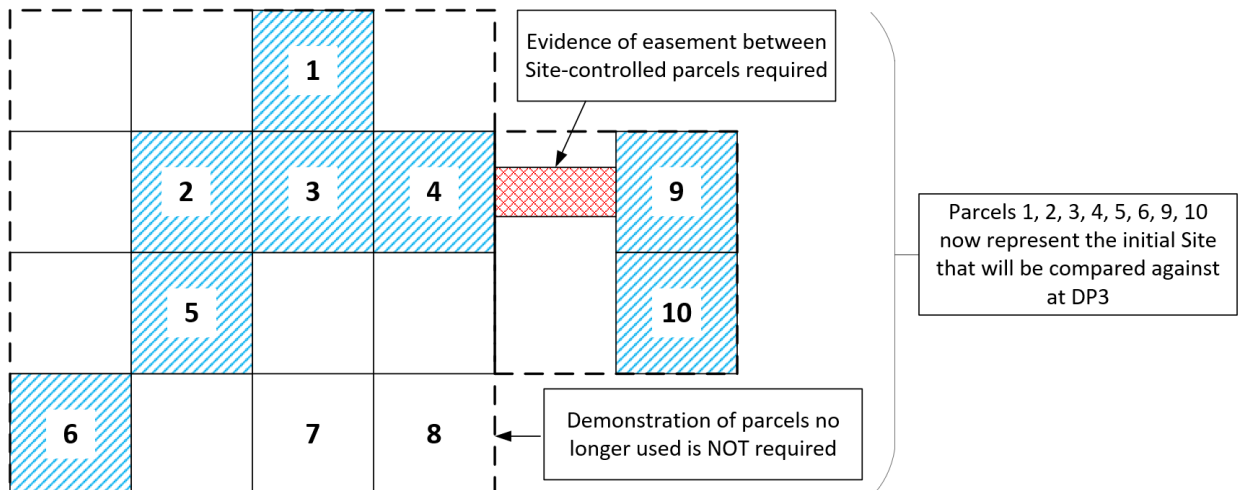
A51 See below:

Acceptable Updates at DP1

SUBMISSION Application

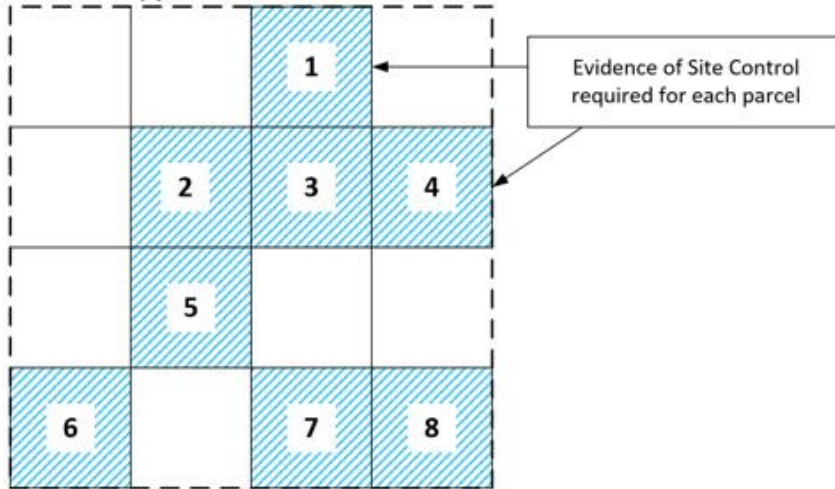


SUBMISSION DP1

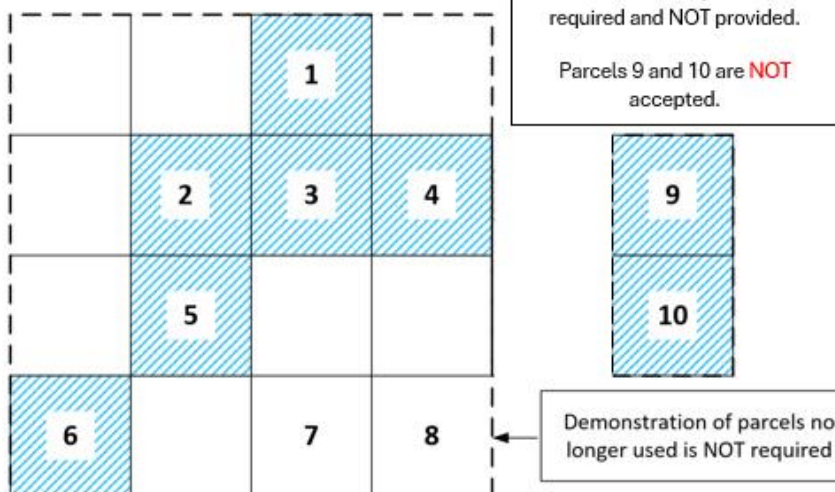


Unacceptable Updates at DP1

SUBMISSION Application



SUBMISSION DP1



The total acreage of parcels 1, 2, 3, 4, 5, 6 does not meet acreage requirements. This submission is **NOT** accepted.

NextGen

Note: For information on the use of NextGen, please reference the User Guide found on the [Applications & Forms page](#). For any technical issues, please email NextGenSupportTeam@pjm.com and copy the appropriate PJM project manager.

Q52 *Where do I submit my DP1 materials?*

A52 Project Developers must submit all materials via NextGen and **not** Queue Point. **Any materials submitted in Queue Point will not be considered or reviewed.** This applies to both legacy TC2 and RRI projects, with the exception of the RRI Deposit, as explained below.

Q53 *I have an RRI project. Should I submit information for all of my deposits in NextGen?*

A53 No, Project Developers with RRI projects should only submit their Study Deposit and Readiness Deposit in NextGen. They should submit their RRI Deposit information via email to systemplanning.admin@pjm.com.

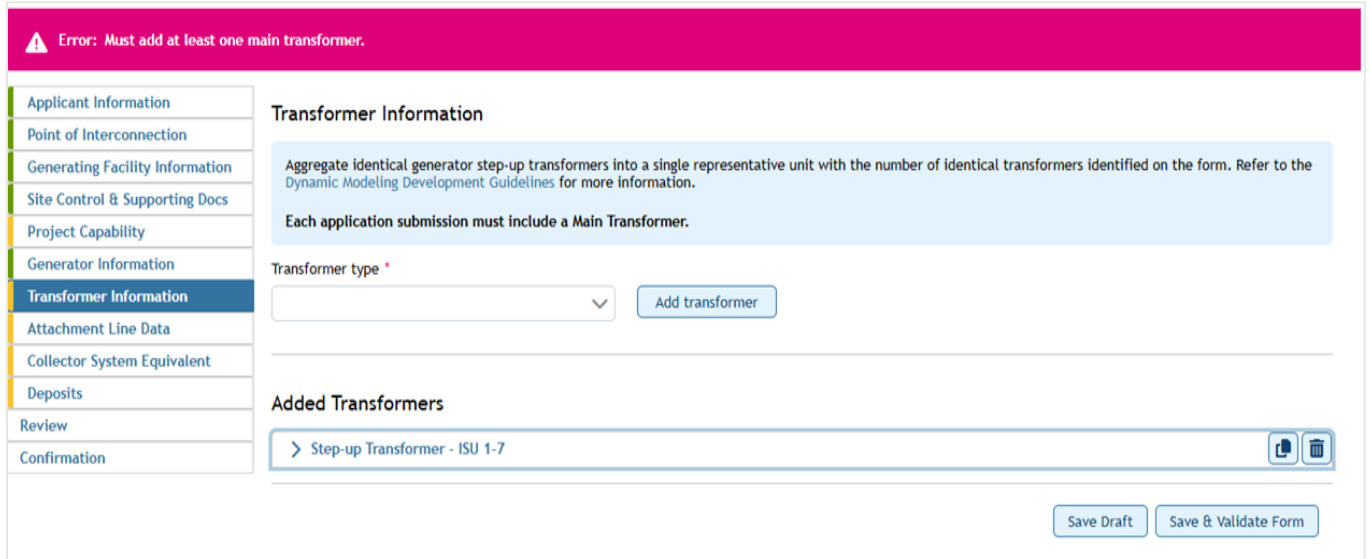
Q54 *How will I know when TC2 DP1 opens and closes?*

A54 Refer to the Cycle Management page in NextGen as well as the timeline posted on pjm.com/planning.

Known Technical Issues With Submissions in NextGen

Known Issue: **I** Workaround: **W**

I: Lower kilovolt projects that do not have a main power transformer. When Project Developer attempts to “save and validate” the Transformer Information, an error appears because NextGen is expecting the PD to add at least one main transformer.



Error: Must add at least one main transformer.

Transformer Information

Aggregate identical generator step-up transformers into a single representative unit with the number of identical transformers identified on the form. Refer to the [Dynamic Modeling Development Guidelines](#) for more information.

Each application submission must include a Main Transformer.

Transformer type *

Added Transformers

> Step-up Transformer - ISU 1-7

W: Add the inverter step-up transformer data as the main transformer again (since it is a required field in Next Gen) and include a note/comment to explain that the project only has an inverter step-up transformer.

I: Cooling class designation for transformer does not have a “single rating” option.

Step-up Transformer - PCS ISU 1 - 25

Assigned machines

Available Machines

>
>>
<
<<

Machines Assigned to Transformer

PCS INV

Transformer name *

Number of identical transformers *

MVA base (Rating 1) *

MVA

Cooling Class Designation(s) for Your Transformer

How many continuous ratings does the transformer have? *

☒ Two ratings
 ☐ Three ratings

⚠ Transformer Ratings must not be null

Rating 1 *

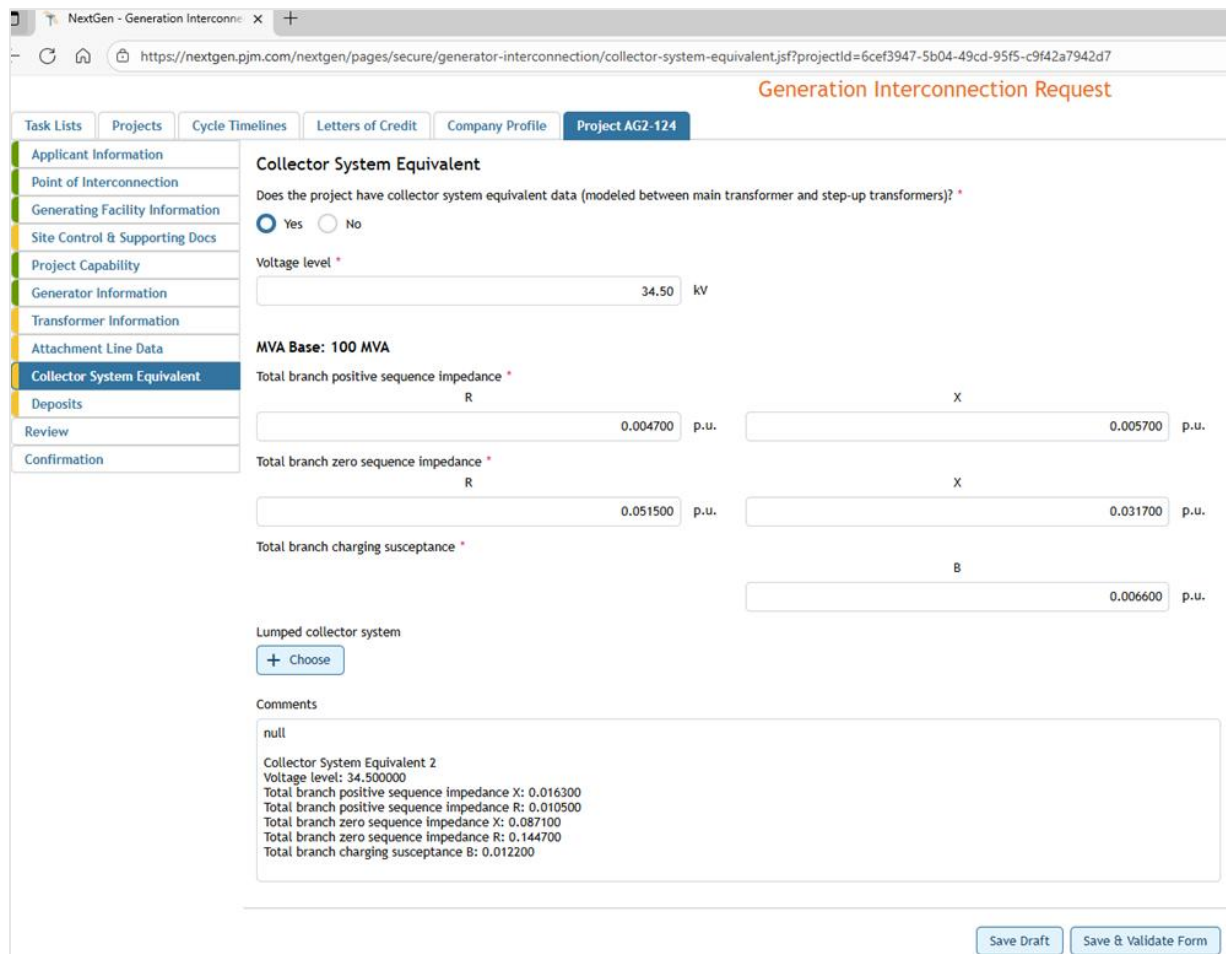
MVA

Rating 1 Cooling Class *

ONAN
▼

W: Duplicate the rating and add a note that the inverter step-up transformer has only one rating and explain the cooling type as well.

I: Queue Point allowed Project Developer to input additional Collector System Equivalent datasets, but Next Gen does not have that same “+ Add Another” button.



Generation Interconnection Request

Task Lists Projects Cycle Timelines Letters of Credit Company Profile **Project AG2-124**

Applicant Information
Point of Interconnection
Generating Facility Information
Site Control & Supporting Docs
Project Capability
Generator Information
Transformer Information
Attachment Line Data
Collector System Equivalent
Deposits
Review
Confirmation

Collector System Equivalent

Does the project have collector system equivalent data (modeled between main transformer and step-up transformers)? *

☒ Yes ☐ No

Voltage level * 34.50 kV

MVA Base: 100 MVA

Total branch positive sequence impedance *
R 0.004700 p.u. X 0.005700 p.u.

Total branch zero sequence impedance *
R 0.051500 p.u. X 0.031700 p.u.

Total branch charging susceptance *
B 0.006600 p.u.

Lumped collector system
[+ Choose](#)

Comments
null

Collector System Equivalent 2
Voltage level: 34.500000
Total branch positive sequence impedance X: 0.016300
Total branch positive sequence impedance R: 0.010500
Total branch zero sequence impedance X: 0.087100
Total branch zero sequence impedance R: 0.144700
Total branch charging susceptance B: 0.012200

[Save Draft](#) [Save & Validate Form](#)

W: Keep/add the second collector system in the comments.

Additional Resources

[Manual 14H](#)

[NextGen Tasks Training for Project Developers](#) [video]

Allowable changes to Site Control:

- FERC Docket Number ER25-1544-000
- Site Control Modification Manual 14H Update (Sept. 2025 IPS Presentation)