Avoided Transmission and Distribution Costs Study - Draft Research Plans

CPUC Webinar

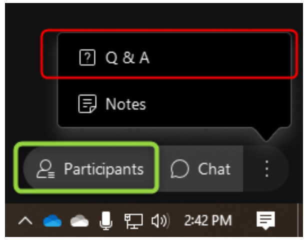
22 August 2025

California Public Utilities Commission

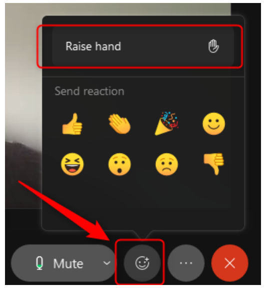
General Information

- **Please use the "raise hand" function if you want ask a question verbally and we will unmute you.**
- **Please use the Q&A function to ask questions.**
  - This leaves the chat free for general announcements
- **This workshop will be recorded, and the recording and the slides will be made available.**

Q&A Panel
Lower-Right



Raise Hand
Lower-Middle



Participants Panel
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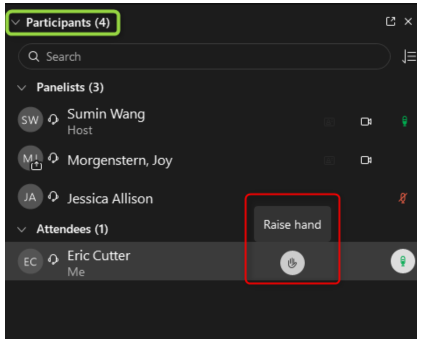
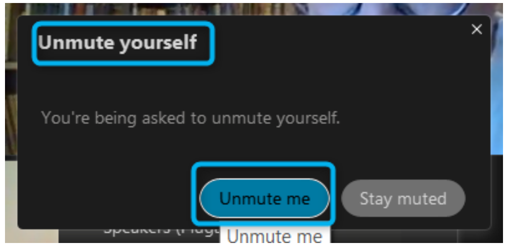


Unmute
A host will unmute you – *then you must click button to unmute yourself*



Agenda

Topic	Presenter	Duration
Introduction and Opening Remarks	Commissioner Houck and ED Staff	3:00-3:10 PM
Avoided Distribution Costs and Q&A	Lawrence Berkeley National Laboratory	3:10-3:55 PM
Break		3:55-4:00 PM
Avoided Transmission Costs and Q&A	Pacific Northwest National Laboratory	4:00-4:45 PM
Next Steps and Close	ED Staff	4:45-4:50 PM

Background

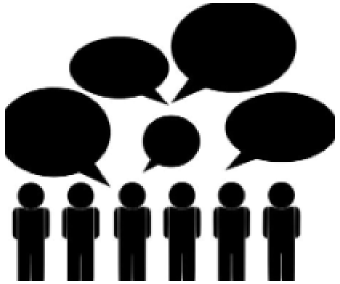
- In Rulemaking (R.) 14-10-003, the Commission issued Decision (D.) 22-05-002, which authorized ED Staff to "conduct analysis on avoided transmission and distribution costs to aid in the development of improved methods to calculate these values."

- In R.22-11-013, the successor proceeding to R.14-10-003, the Commission issued D.24-04-010, which authorized reimbursable ratepayer funds for an avoided transmission and distribution (T&D) costs study.

Opening Remarks

Commissioner Houck

General Ground Rules



- Staying on time:
  - LBNL and PNNL will present their draft research plans and the work they have done for the T&D Study
  - LBNL and PNNL will respond to questions at the end of each of their presentations
  - Either raise your hand or type your question into chat and ED Staff will unmute you or ask it for you during the Q&A segments
- Maintaining our purpose: All questions should relate to the avoided transmission and distribution costs study
  - Subject matter outside of these topics will be directed back to the key topics
- Matters outside the scope of R.22-11-013 Track 1 may not be discussed at this webinar

Lawrence Berkeley National Laboratory (LBNL) Presentation: Avoided Distribution Cost Study Research Plan

Avoided Distribution Cost Study Research Plan

Miguel Heleno
Lawrence Berkeley National Laboratory

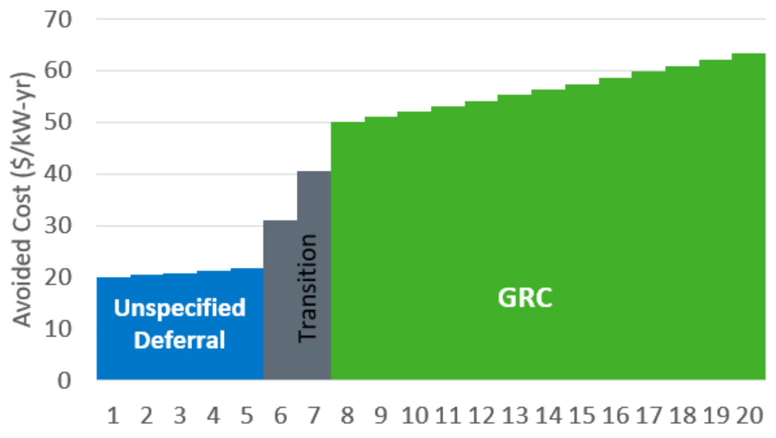
Energy Technologies Area
BERKELEY LAB

Outline

- Current Methodology
- Challenge
- Objectives and Approach
- Proposed Methodology
- Discussion

Current Methodology

- **Short-term avoided costs:** *unspecified deferrals* derived from counterfactual distribution deficiencies (with and without DERs) valued by data on *specified deferrals* (DDOR).
- **Long-term avoided costs:** marginal cost estimates from General Rate Case (GRC) filings, reflecting broader cost trends beyond identified projects.
- **Transition period costs:** linear interpolation of short-term and long-term avoided costs during a period of 2 years.

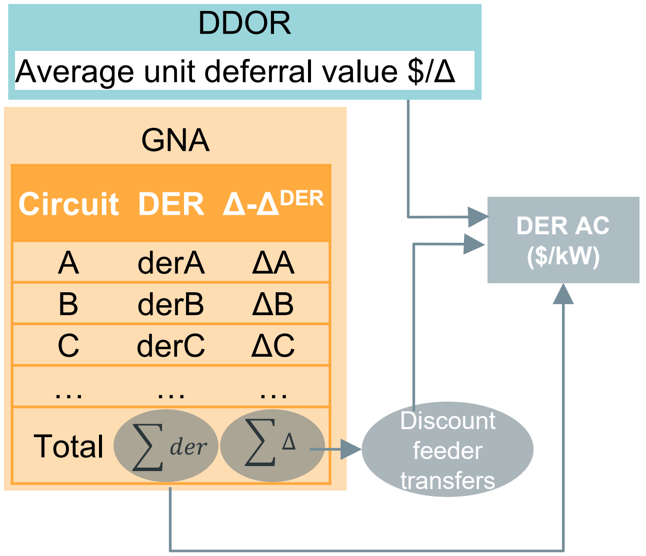


Current Methodology

- **Estimate DER-avoidable deficiencies**:
Use circuit-level GNA data to compute deficiencies with and without DERs. Calculate total deficiencies and adjust for low-cost feeder transfers.

- **Estimate unit cost of deferral**:
Derive an average $/kW cost of addressing deficiencies from DDOR filings by dividing the total proposed investment by the total associated capacity needs.

- **Calculate system-level avoided cost**:
Multiply the DER-avoidable capacity (kW) by the unit cost ($/kW) and divide by the total DER capacity in the system to produce a system-level avoided cost in $/kW-yr.



Challenges

- **Challenge 1: For some circuits, the current methodology overestimates the quantity of deficiencies DERs can avoid.**

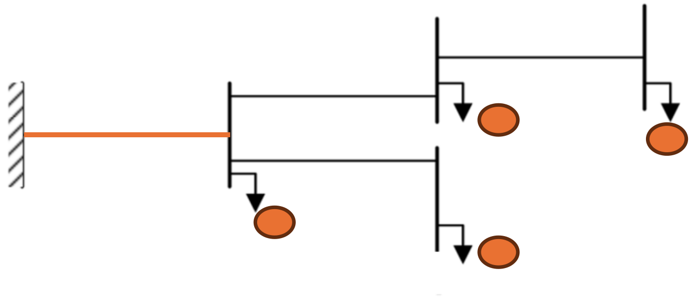


Figure 1.a. All DERs contribute to reducing congestion and avoid deficiencies.

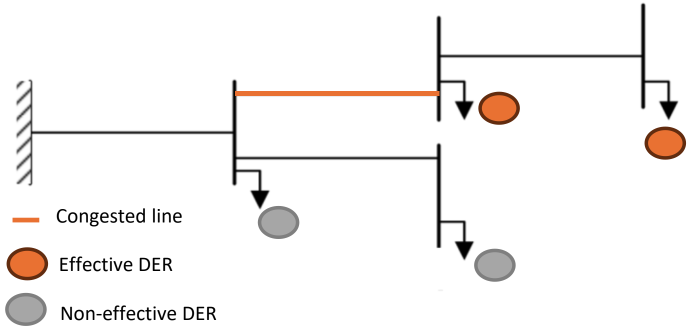
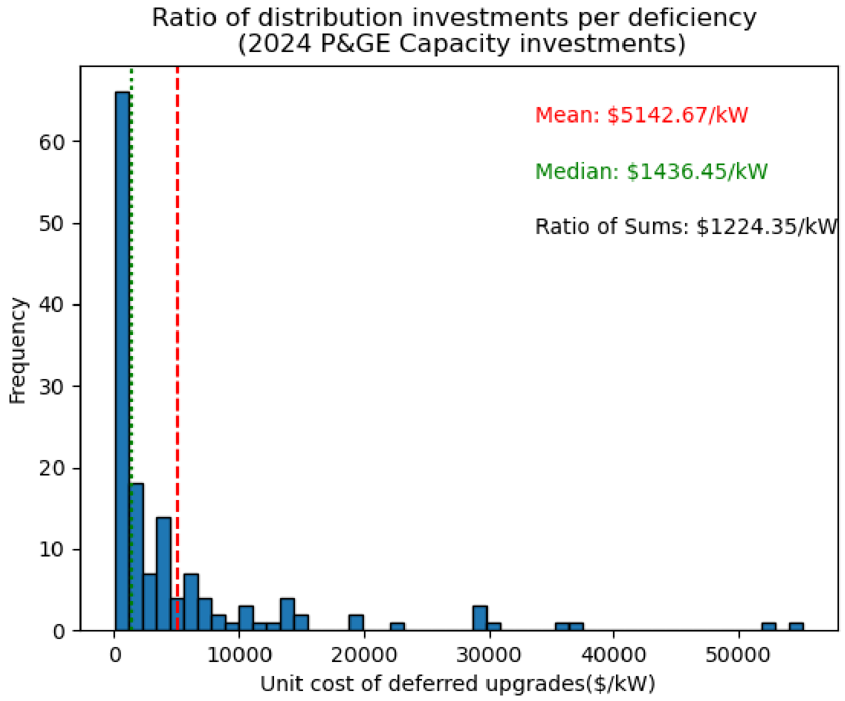


Figure 1.b. Only a portion of DERs contributes to reducing congestion and avoid deficiencies.

Challenges

- **Challenge 2: The estimated dollar value per kW of distribution deferral is a single value per utility, based on a broad range of potentially non-representative projects.**

A single value for the unit cost of deferred distribution upgrades is obtained for each utility territory. This value is obtained using a wide range of project costs and corresponding circuit deficiencies.



Challenges

Challenge 3: The method for accounting for non-deferrable capacity due to feeder transfers is very coarse

- Feeder transfer assumptions were derived from earlier studies and require updates.
- Discounting for feeder transfers directly reduces the estimated avoided cost. Yet, transfers are likely to occur when DER deferral is high.

Challenge 4: The current methodology only captures capacity deferral opportunities

- Current methodology only accounts for capacity deferral, excluding DER value in deferring voltage support and reactive power projects.
- How does accounting for non-capacity deficiencies change DER avoided costs?

Challenges

Challenge 5: Discrepancies exist between short-term avoided costs and long-term costs

- Avoided costs in years 1-5 are based on short-term unspecified costs while 8-20 are based on cost-of-service declared in GRC.
- The current ACC methodology does not clarify nor adequately reconcile these differences.

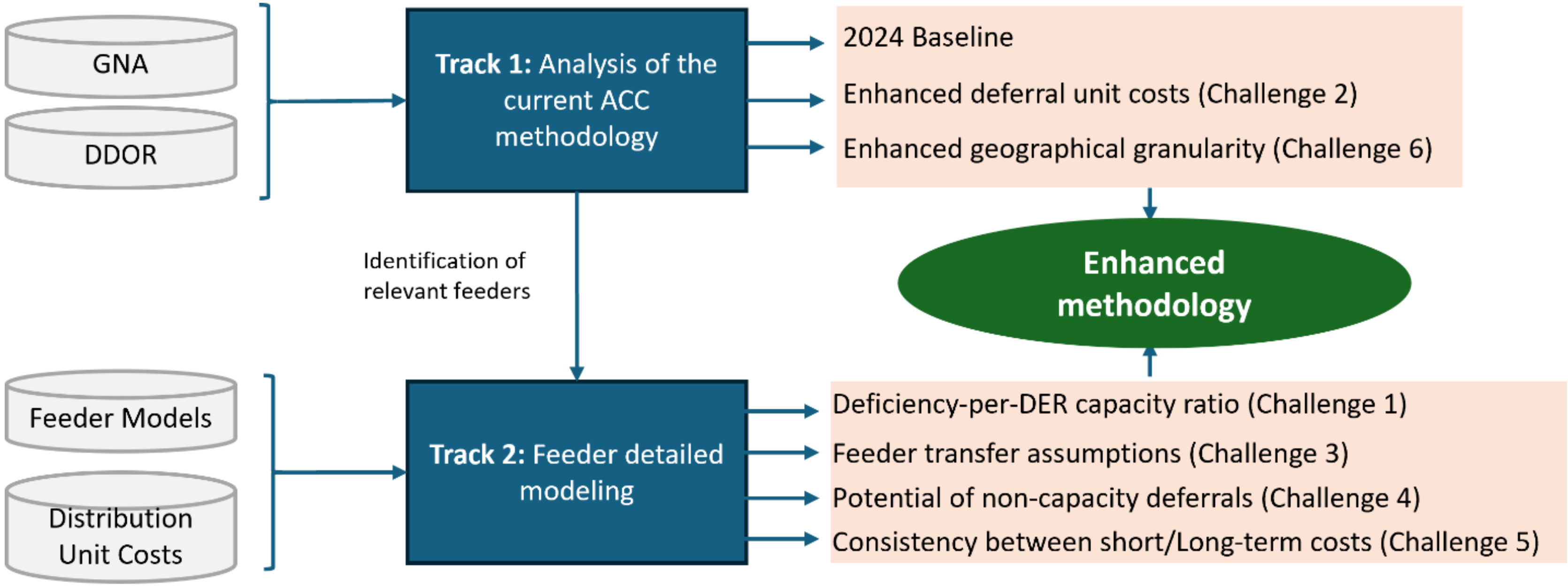
Challenge 6: The current methodology does not capture locational value

- The existing methodology calculates avoided costs by dividing the estimated deferral value by the total DER capacity, significantly lowering the per-unit ($/kW) value.
- How does accounting for non-capacity deficiencies change DER avoided costs?

Objectives

- Propose improvements to the representation of DER contributions to capacity deferral at the circuit level and reconcile short- and long-term avoided cost estimates.
- Replace utility-wide average deferral costs with more accurate unit cost functions and derive DER avoided costs at more granular spatial scales.
- Explore ways to refine treatment of load transfers using circuit data to assess the potential of considering non-capacity deferrals in the distribution avoided costs.

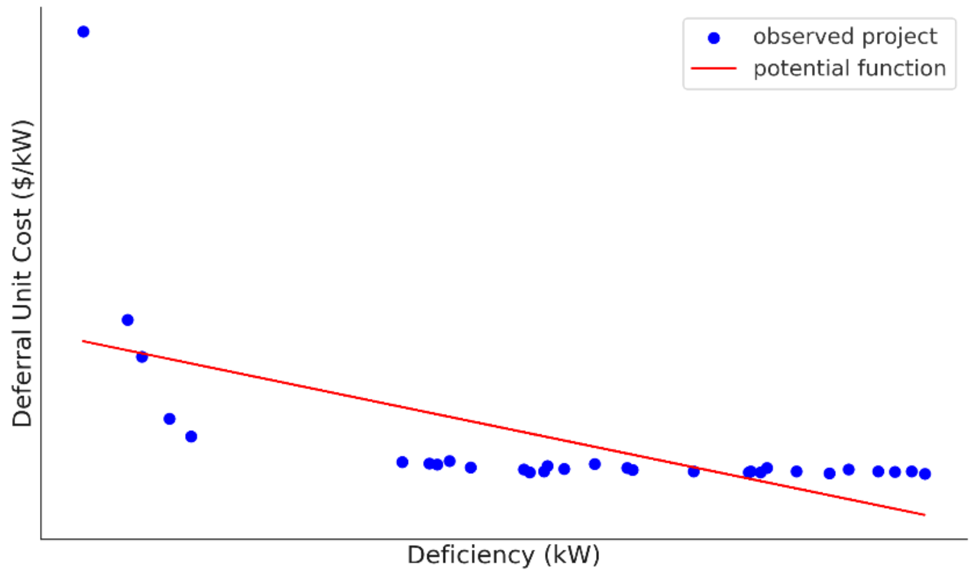
Approach


GNA
DDOR
Track 1: Analysis of the current ACC methodology
2024 Baseline
Enhanced deferral unit costs (Challenge 2)
Enhanced geographical granularity (Challenge 6)
Identification of relevant feeders
Enhanced methodology
Feeder Models
Distribution Unit Costs
Track 2: Feeder detailed modeling
Deficiency-per-DER capacity ratio (Challenge 1)
Feeder transfer assumptions (Challenge 3)
Potential of non-capacity deferrals (Challenge 4)
Consistency between short/Long-term costs (Challenge 5)

Track 1: Enhancing Unit Costs Accuracy

Enhanced deferral unit costs via regression model

- Propose using regression on DDOR project data to estimate deferral unit cost as a function of deficiency magnitude.
- This approach captures variation in deferral value across deficiency sizes, improving accuracy over a single average value.

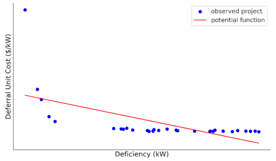


Track 1: Enhancing Granularity

Circuit-level calculations of DER avoided costs

- Apply deferral cost functions and calculate DER value at the circuit level.
- Explore aggregations DER avoided costs across spatial levels (e.g., county, climate zone), comparing results to utility-wide values and discussing implications for ACC.

DDOR



GNA					
Circuit	**DER**	**Δ-Δ^{DER}**	**$\frac{\Delta\text{-}\Delta^{DER}}{DER}$**	**Unit cost \$/kW**	**DER AC \$/kW**
A	derA	ΔA	xA	cA	xA * cA
B	derB	ΔB	xB	cB	xB * cB
C	derC	ΔC	xC	cC	xC * cC
…	…	…	…	…	…

DER avoided cost per circuit

Circuit-level analysis Track 2

Different options of aggregation

Track 2: Circuit-level Modeling

Detailed Feeder model to derive the ratio of deficiencies per DER ratio

- Run the modified LBNL LODGE model with and without DERs. The model minimizes the system capacity needs under power flow and equipment constraints.
- Take the difference between deficiencies with and without DERs and divide by the DER capacity.

$$\min \Delta$$

$$\Delta = \sum_{(i)\in N} \Delta^{+}{}_{i}$$

$$P_0 \le P_0^{\max}$$

$$P_{ij} = \sum_{k:(j,k)\in L} P_{jk} - P_j + lf_{ij}{}^{P} \cdot P_{ij} \quad \forall (i,j) \in L$$

$$P_{ij} \le P_{ij}^{\max} \quad \forall (i,j) \in L$$

$$\sum_{k:(0,k)\in L} P_{0k} - \sum_{j:(j,0)\in L} P_{j0} = P_0^{\text{sub}}$$

$$P_i = -P_i^{\text{Load}} + \alpha_i \cdot DER^{GNA} + \Delta^{+}{}_{i} \quad \forall i \in N$$

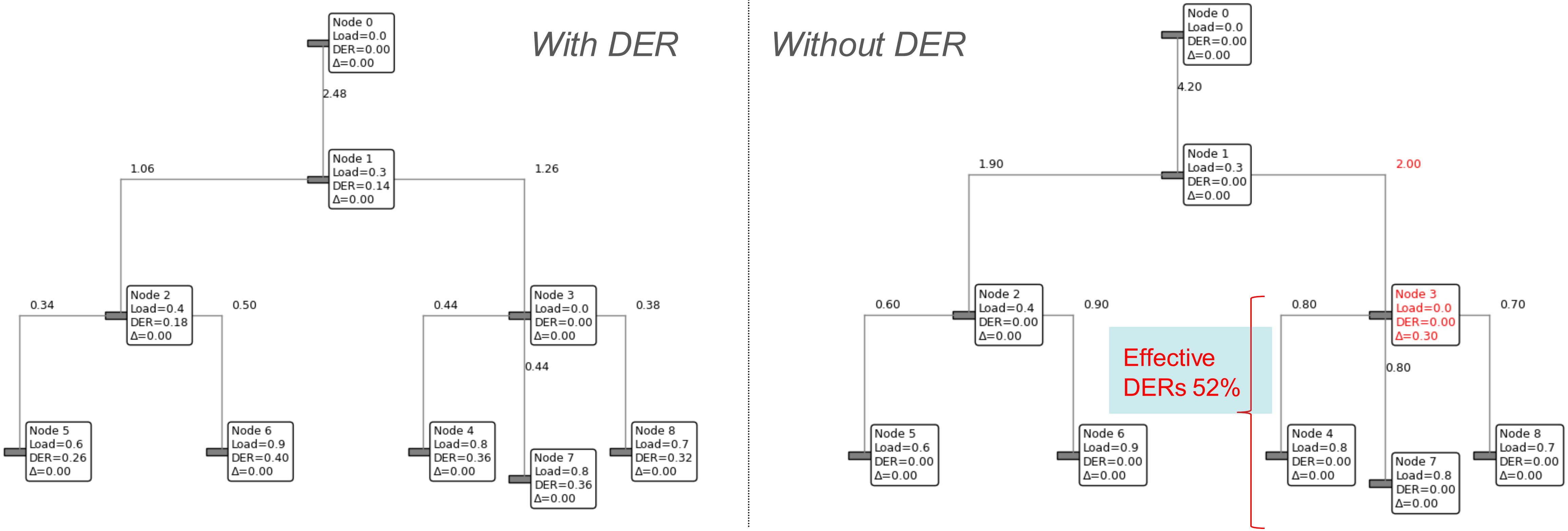
$$\frac{\Delta - \Delta^{\text{DER}}}{\text{DER}}$$

The amount of deficiencies that DERs can address is a characteristic of each circuit

Example

9 Node Feeder, Load: 5MW, DER: 2MW

Δ-Δ^{DER} : 0.3 MW
(Δ-Δ^{DER}) / DER: 0.3 / 2 = 0.15



Track 2: Explore Additional Values

Feeder Transfers

- Review utility practices and feeder equipment to identify load transfer areas and assess their interaction with DERs in the circuit model.
- Use circuit-level modeling to quantify the contribution of feeder transfers to capacity needs.

Non-capacity deferrals

- Assess the incremental value of voltage and reactive power by adding voltage and reactive flow constraints to the circuit-level optimization model

$$Q_{ij} = \sum_{k:(j,k)\in L} Q_{jk} - Q_j + lf_{ij}{}^{Q} \cdot Q_{ij} \quad \forall (i,j) \in L$$

$$v_j = v_i - 2 \cdot (R_{ij} \cdot P_{ij,t} + X_{ij} \cdot Q_{ij,t}) \quad \forall (i,j) \in L$$

$$v^{\min} \leq v_j \leq v^{\max} \quad \forall j \in N$$

$$\sum_{k=(0,k)\in C} Q_{0k} - \sum_{j:(j,0)\in C} Q_{j0} = Q_0^{\text{sub}}$$

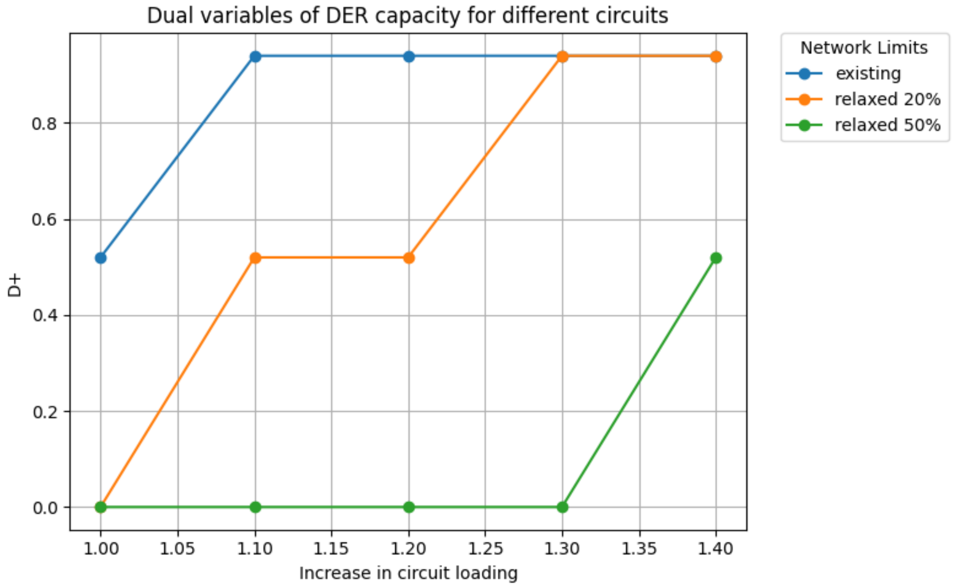
$$Q_i = -Q_i^{\text{load}} + Q_i^{\text{cap}} \quad \forall i \in N, i \neq 0$$

Track 2: Long-term Avoided Costs

- Extend the short-term optimization model to long-term analysis by introducing a decision variable for DER capacity beyond the GNA horizon (DER^{Beyond}).

- Use the dual values of DER^{Beyond} bounds to estimate long-term avoided costs, applying the deferral cost function and comparing to GRC values.

$$P_i = -P_i^{\text{Load}} + \alpha_i \cdot DER^{GNA} + \Delta^+{}_i + \alpha_i \cdot DER^{Beyond} \quad \forall i \in N$$
$$DER^{Beyond} \geq 0 : D^+$$



This metric expresses the ability of DERs to address deficiencies in the long-run.

Q&A?

LBNL Team

Miguel Heleno

Yujia Li

Alex Moreira

Jeff Deason

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Break

Please return by 4:00 PM

Pacific Northwest National Laboratory (PNNL) Presentation: Avoided Transmission Cost Study Research Plan

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CPUC Avoided Transmission and Distribution Cost Study to Support the ACC

Avoided Transmission Costs Draft Research Plan

Eran Schweitzer
Kyle Wilson
Brittany Tarufelli

Pacific Northwest National Laboratory

U.S. DEPARTMENT OF ENERGY BATTELLE

PNNL is operated by Battelle for the U.S. Department of Energy

PNNL-SA-214025

Agenda

- Introductions & Background
- Study Objectives
- Overview of CPUC's Current Practice for Valuing Transmission Avoided Costs
  - PNNL's Assessment of Current Practice
- Proposed Method for Valuing Transmission Avoided Costs: Power Flow Assessment
  - Overview, Key Inputs, Impact of Load Reduction, Marginal Investment, and Allocation
- Stakeholder Q&A

Introductions & Background

- Pacific Northwest National Laboratory (PNNL) has been engaged by the CPUC to perform a study that explores and selects an improved methodology to estimate avoided electricity transmission infrastructure costs
- PNNL is a multi-program national laboratory operated for the U.S. Department of Energy (DOE) by Battelle Memorial Institute under Contract No. DE-AC05-76RL01830

PNNL Team Leads

Eran Schweizer, PhD
Electrical Engineer, Power Systems Engineering Task Lead

Kyle Wilson, PhD
Economist, Economics Task Lead

Study Objectives

- **Objective:** Develop a methodology to help the CPUC derive the required load reduction to avoid certain transmission capacity additions and to ultimately determine estimates of transmission avoided costs to be included in the Avoided Cost Calculator (ACC). The ACC identifies costs to utilities and ratepayers avoided because of DERs

- **Key Research Objectives:**
  - Assessment of the CPUC's current methods for valuing marginal transmission avoided costs
  - Provide a methodology that is repeatable, not solely dependent on utility empirical data, provides a clear and consistent framework for valuing transmission avoided costs, and provides increased geographic granularity of transmission avoided costs

Overview of Current Practice

- Utilities determine a set of projects that are needed due to load growth and are judged as deferrable
- These projects are weighed against the projected load growth associated with them to calculate the marginal cost of transmission
- The current ACC uses different methods for location specific needs and system-wide needs (Table 1)
    - ✓ DTIM uses system-wide load growth forecasts to estimate and overall avoided cost
    - ✓ LNBA estimates the marginal avoided cost based on the load reduction at a specific location and then adjusts the cost to a general estimate using peak loading percent

	Discounted Total Investment Method (DTIM)	Locational Net Benefit Analysis (LNBA)
Metric Interpretation	The value of deferring the revenue requirement cost of the project and all future replacements by one year	The deferral by one year of all investments in the multi-year capital plan
Load growth	System load	Locational fraction of load
Service Territory Adjustment	None	Peak loading %

Table 1: Key Inputs to Avoided Transmission Calculation

PNNL's Assessment of Current Practice

Key Strengths

- Current projects have more accurate cost estimates
- No modeling on *how* DER reduce load, the calculation is simply "*if* DER would reduce load, this is what it would be worth"

Open Questions

How are the transmission projects that are due to load growth selected/identified?

Example:

- PG&E's 2019 GRC phase II filing: 6 of 73 projects judged to be deferrable*
- SEIA testimony from November 20th, 2020, cites the same testimony but claims 27% of projects are capacity related**

*Pacific Gas and Electric Company 2020 General Rate Case Phase II Exhibit (PG&E-2) Ch. 4.
**Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association, November 20, 2020.

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Proposed Methodology

- PNNL proposes an approach that utilizes the CAISO transmission planning dataset and approved transmission portfolio to investigate the impact of load growth on the transmission projects
- The proposed methodology assesses how load reduction changes the need for transmission projects
- This information is used to calculate transmission avoided capacity costs and distribute those costs over time and to geographic zones

The assessment does not claim that any approved project should or will be avoided. Rather, it asks what it *would have taken* to avoid that project and extrapolates to future undetermined projects

Proposed Methodology

Data Inputs

- Leverages CAISOs Transmission Planning Process* (TPP)
  - Provides approved projects with a cost estimation
  - Prepares power flow cases with load forecast aligned with the CPUC and CEC processes

Methods

- Develop a power flow based calculation method to determine load reduction to associate with each transmission project
- Use power flow sensitivities to spatially distribute the load reduction

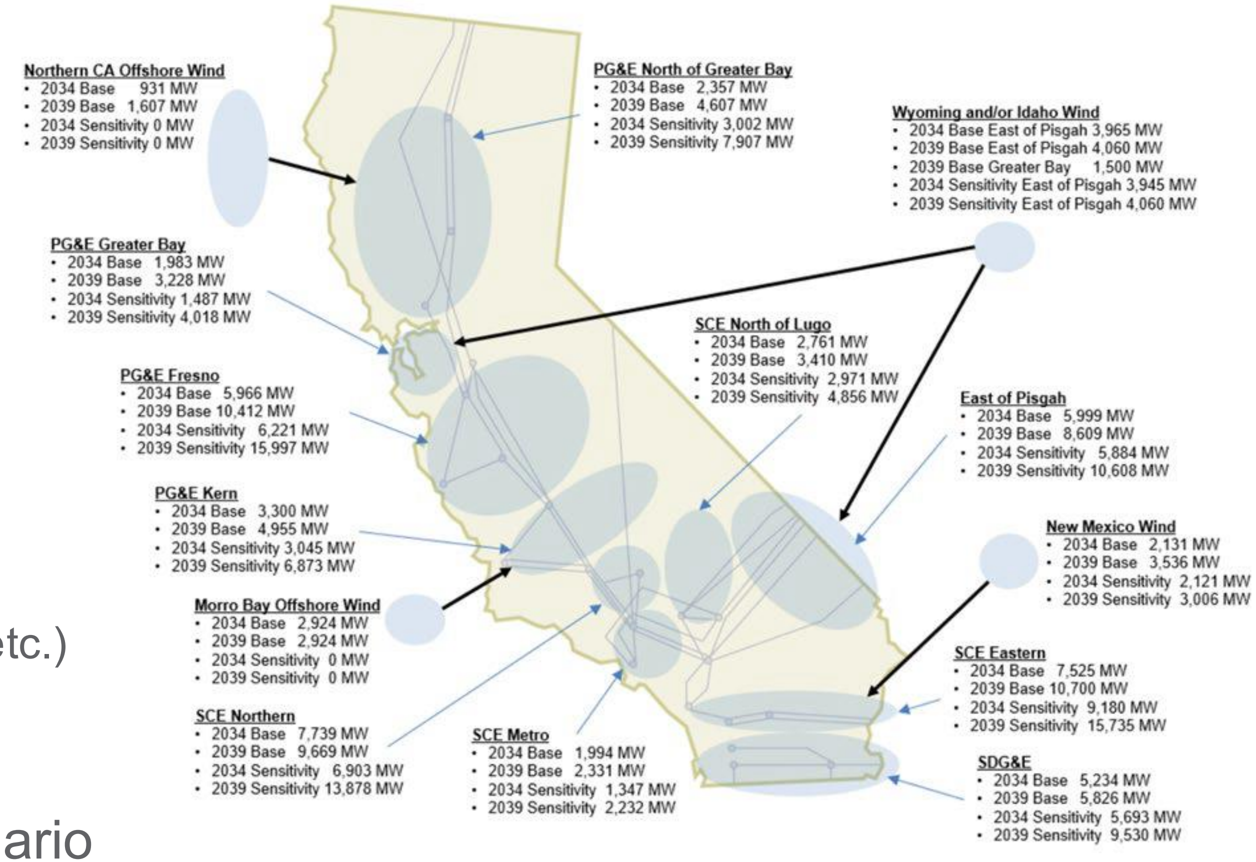
Key Improvements

- Data driven approach to determine included transmission projects
- Transparent and repeatable methodology for assessing the impact of load reduction
- Natural spatial allocation of load reduction, as opposed to one system wide value

*https://www.caiso.com/generation-transmission/transmission/transmission-planning

Key Inputs

- Power flow cases from CAISO Transmission Planning Portal
  - Base cases
  - Change files
  - Contingency definitions
- Geographic zone definitions
  - Transmission planning zones will be used from power flow models
- Scenarios: there are two kinds
  - Operating points (summer peak, winter peak, etc.)
    - ✓ Only summer peak will be used initially
  - Different study years (2029, 2034, 2039)
- Peak load allocation factor (PCAF) by scenario
  - Derived like the current ACC*



CAISO Transmission Planning Zones From the 2024-2025 TPP**

* https://www.ethree.com/wp-content/uploads/2025/02/2024-ACC-Documentation-v1b_clean.pdf
** https://www.caiso.com/documents/iso-board-approved-2024-2025-transmission-plan.pdf

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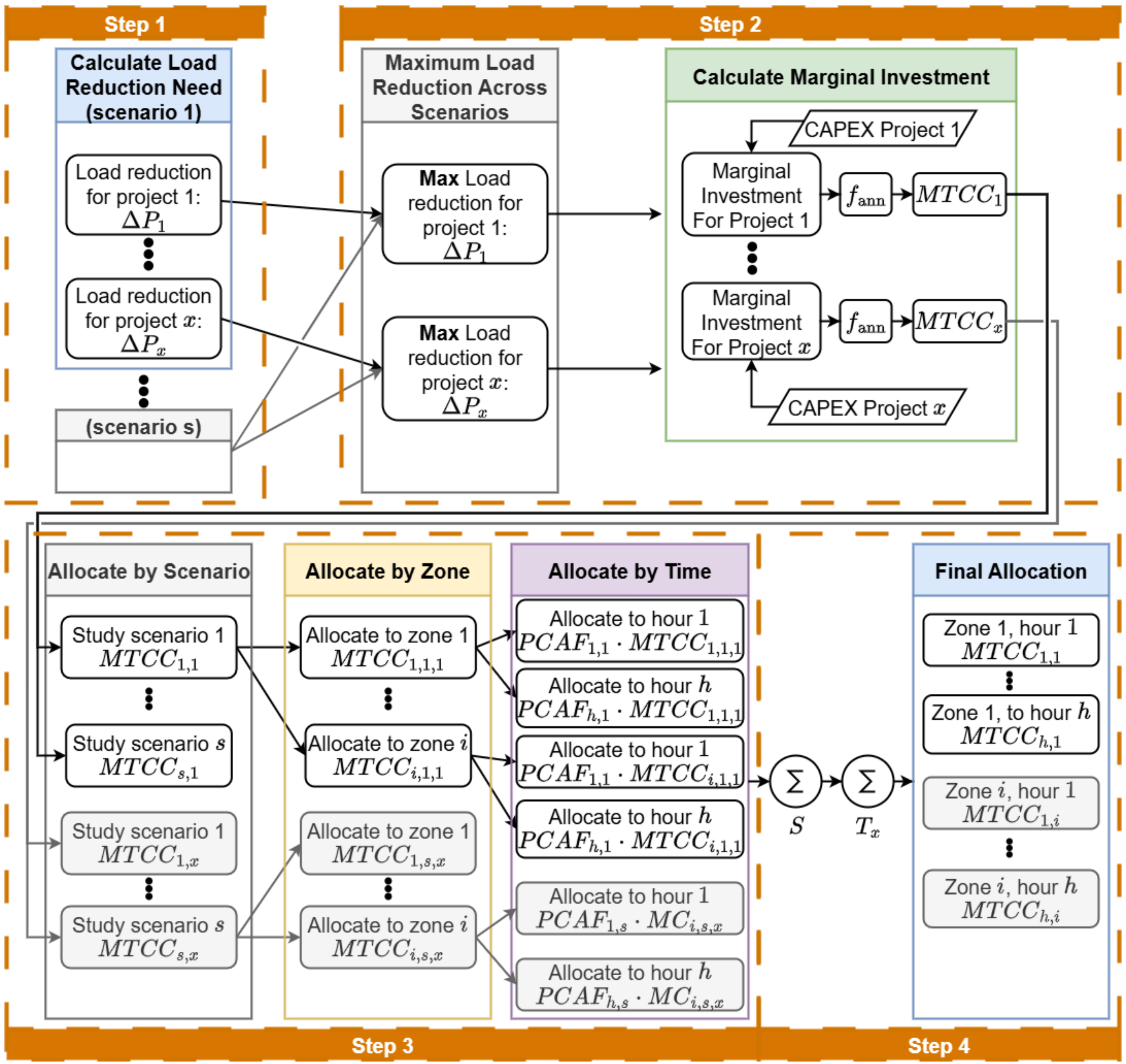
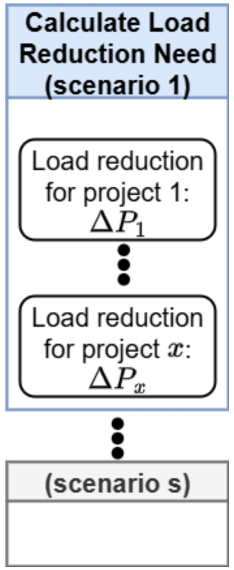
Methodology Overview

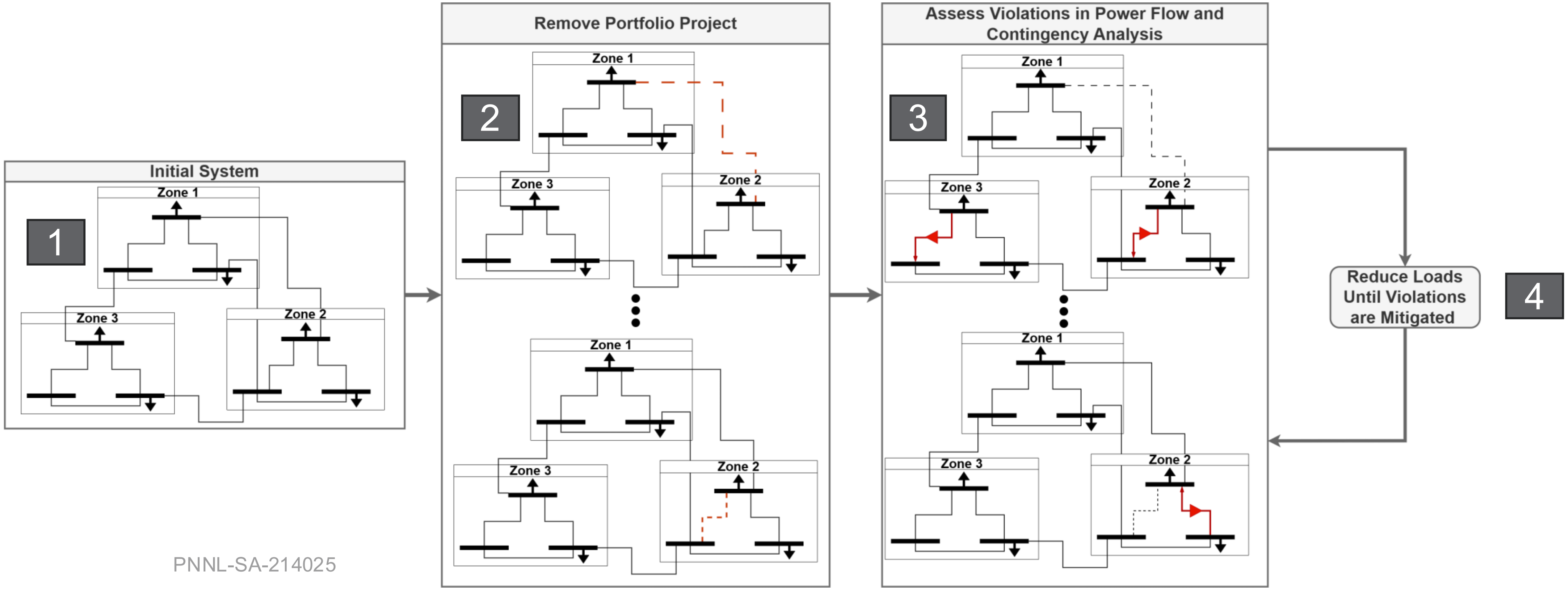
1. Calculate **load reduction** needed to defer each transmission project
2. Calculate **marginal transmission capacity cost (MTCC)** based on project cost and maximum needed load reduction
3. Allocate investments
   a) by **scenario**
   b) by geographic transmission **zone**
   c) by **time**
4. Sum over **scenarios** and **projects** for final **zone** & **time** allocation



Step 1: Calculate Load Reduction

1. Given a scenario with a portfolio of multiple projects (initial system)
2. Remove each project, one at a time
3. Assess additional violations in contingency analysis
4. Reduce load until new violations are eliminated





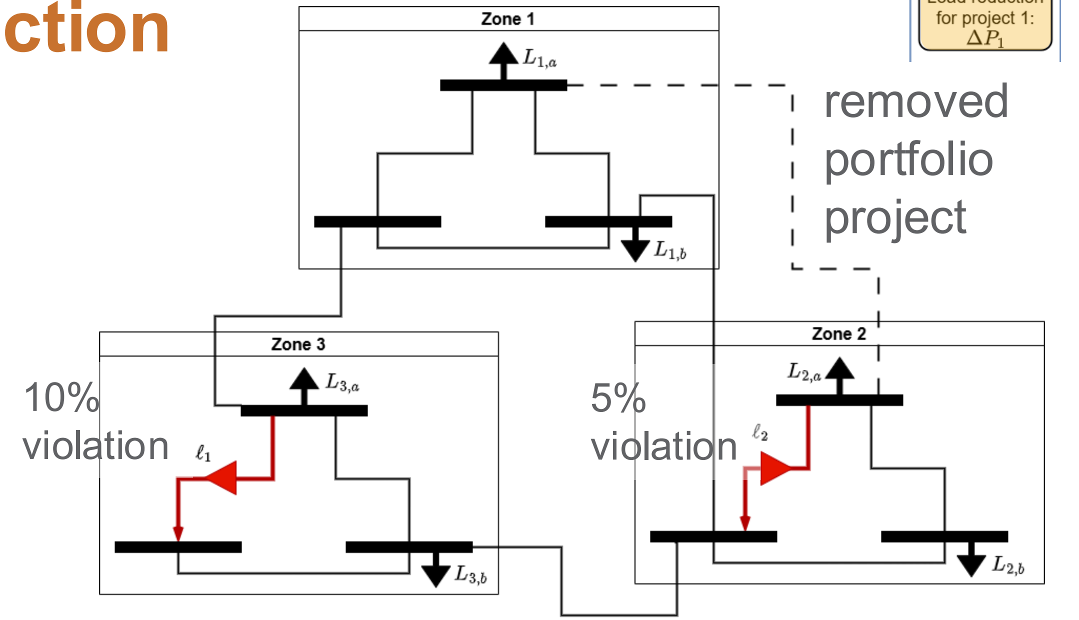
Calculate Load Reduction Need (scenario 1)

Load reduction for project 1: ΔP_1

Step 1: Calculate Load Reduction

Example

- After removing portfolio project (dashed line) 2 new violations are observed (red)
- Take a step reduction in load, ΔP_t (e.g., 1 MW)
- Weight each violation based on its magnitude, w_l (larger magnitude, larger weight)
- Distribute each violation to the zones based on Power Transfer Distribution Factors (PTDFs)*, $w_{i,l}$
  - Only consider reduction in zones that will help alleviate the violation.
- Distribute zone reduction to individual load buses based on load participation factors
  - fraction of load compared to total zone load



	Zone 1	Zone 2	Zone 3
ℓ_1	$\mathrm{PTDF}_{l_{1,1}} = -0.15$	$\mathrm{PTDF}_{l_{1,2}} = +0.1$	$\mathrm{PTDF}_{l_{1,3}} = -0.4$
ℓ_2	$\mathrm{PTDF}_{l_{2,1}} = -0.06$	$\mathrm{PTDF}_{l_{2,2}} = +0.3$	$\mathrm{PTDF}_{l_{2,3}} = +0.2$

Zone i load reduction Step t

$\Delta P_{i,t} = \Delta P_t \left(\text{Weighted Violation} \right)^T \bullet \text{Weighted Zones}$

Weighted Violation

	w_l	Reduction [MW]
ℓ_1	$\frac{10}{15}$	$1\text{MW} \times \frac{10}{15} = 0.67\text{MW}$
ℓ_2	$\frac{5}{15}$	$1\text{MW} \times \frac{5}{15} = 0.33\text{MW}$

Weighted Zones

	Zone 1	Zone 2	Zone 3
ℓ_1	$0.67 \times \frac{0.15}{0.15+0.4} = 0.1818$		$0.67 \times \frac{0.4}{0.15+0.4} = 0.4848$
ℓ_2		$0.33 \times \frac{0.3}{0.3+0.2} = 0.2$	$0.33 \times \frac{0.2}{0.3+0.2} = 0.1333$
Total	0.1818	0.2	0.6181

*PTDFs are flow sensitivities. They capture how an injection or transfer is distributed to each branch in the system

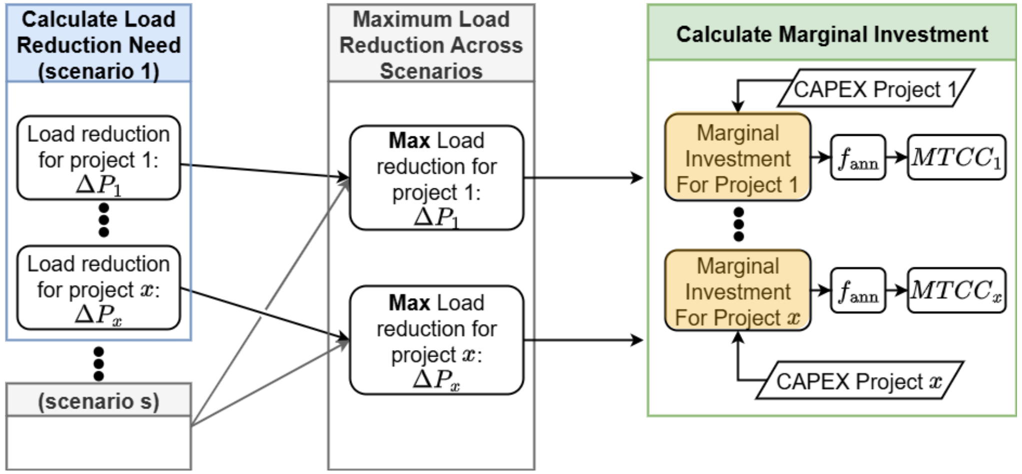
Step 1: Calculate Load Reduction

Edge Cases

- If one of two edge cases are encountered, the project is removed from consideration

	Edge Case 1	**Edge Case 2**
Description: Following project removal…	**No** violations observed	Violations **persist** irrespective of load reduction
Intuition	Project needs are not captured by power flow contingency analysis	1) Project needs are not captured by the power flow contingency analysis 2) The project is not deferrable via load reduction

Step 2: Calculate Marginal Investment



The marginal investment for each transmission project, x, with respect to load growth, is the ratio of the transmission project's cost, $c(x)$ and the load reduction, ΔP, that would be needed to eliminate the need for the project

$$MC_x\ [\$/\text{MW}] = \frac{PV\big(c(x)\big)}{\max_{s \in S} PV\big(\Delta P_{s,x}\big)}$$

Notation	Definition
S	Set of scenarios
$PV(\cdot)$	The present value function
MC_x	Marginal Investment for project x
$c(x)$	CAPEX for project x
$\Delta P_{s,x}$	Load reduction for project x in scenario s

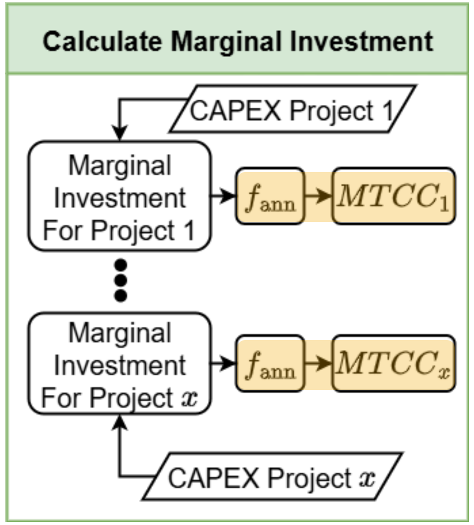
Intuition

- Marginal investment increases for two reasons:
  - **Higher** costs, $c(x)$ → the more expensive the project is, the bigger the deferment benefit
  - **Lower** load reduction, ΔP → the smaller the necessary load reduction, the bigger the benefit of deferment
- Since capital investments are single decisions, the maximum necessary load reduction needs to be considered

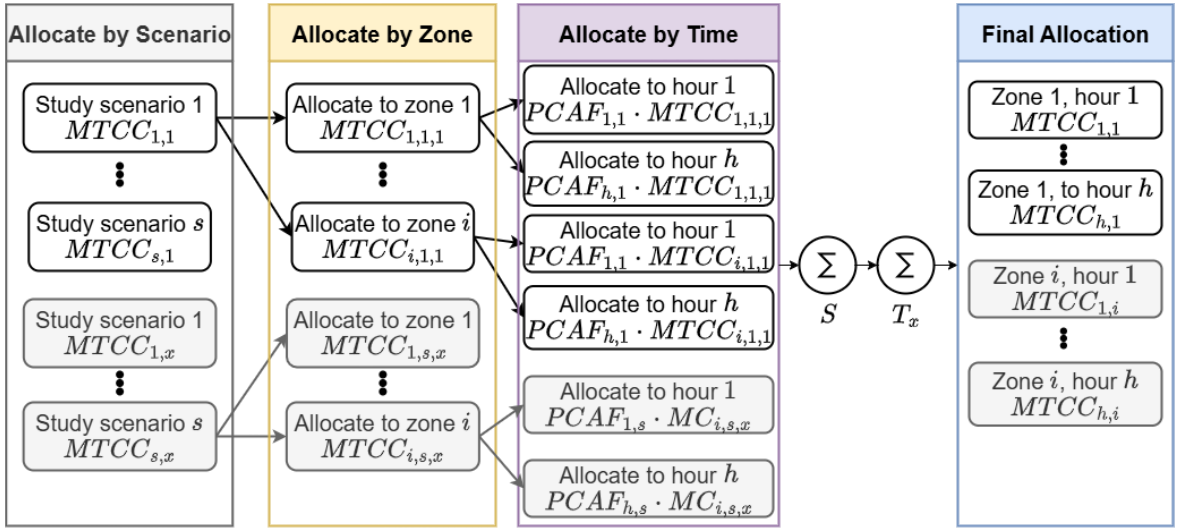
Note:
Ratio formation is very similar to current ACC.
The derivation of ΔP is new.

Step 2: A Note on Marginal Transmission Capacity Cost

- The current ACC uses different methods for location-specific needs and system-wide needs
  - LNBA and DTIM
- Both methods annualize the avoided cost using a Real Economic Carrying Charge (RECC) factor to produce MTCC estimates that represent the value of deferring the revenue requirements by one year
- We will use a similar RECC factor to annualize the avoided costs and produce estimates that can be compared to current and previous ACC estimates
- Our results will produce a system-wide estimate, and the allocation by zone will provide location-specific estimates



Step 3: Allocate Investments & Step 4: Sum for Final Allocation



- **Step 3:** The MTCC for each project is allocated in three steps:
  - To each **scenario**

$$\mathrm{MTCC}_{s,x} = \frac{\mathrm{PV}(\Delta P_{s,x})}{\sum_{s \in S} \mathrm{PV}(\Delta P_{s,x})} \cdot MTCC_x$$

  - Within each scenario to each geographic **zone**

$$MTCC_{i,s,x} = \frac{\Delta P_{i,s,x}}{\Delta P_{s,x}} \times MTCC_{s,x}$$

  - Within each scenario and zone to each annual **hour**

$$\mathrm{PCAF}_{h,s} \times MTCC_{i,s,x}$$

- **Step 4:** The final allocation by **zone** and **hour** sums over the scenarios and transmission projects

$$MTCC_{h,i} = \sum_{x \in T_x} \sum_{s \in S} \mathrm{PCAF}_{h,s} \times MTCC_{i,s,x}$$

Notation	Definition
$PV(\cdot)$	The present value function
S	Set of scenarios
T_x	Set of transmission projects
$MTCC$	Marginal transmission capacity cost
$MTCC_s$	MTCC for project x
$MTCC_{s,x}$	MTCC in scenario s for project x
$MTCC_{i,s,x}$	MTCC in zone i and scenario s for project x
$MTCC_{h,i}$	Final MTCC for hour h and zone i
$\Delta P_{s,x}$	Load reduction in scenario s for project x
$\Delta P_{i,s,x}$	Load reduction in zone i and scenario s for project x

Summary

- Develops a data-driven process to determine the input set of transmission projects from the CAISO TPP
  - ✓Repeatable
  - ✓Not solely dependent on utility empirical data
- Power flow modeling approach enables a standardized process for determining the load reduction associated with the ability to defer or avoid a project
  - ✓Provides a clear and consistent framework for valuing transmission avoided costs
- Allows for spatial differentiation of load reduction at a more granular level
  - ✓Provides increased geographic granularity of transmission avoided costs

Stakeholder Q&A

Pacific Northwest
NATIONAL LABORATORY

Thank you

PNNL-SA-214025

Key Documents and References

- D.22-05-022 - Commission Decision Adopting the 2022 Avoided Cost Calculator Energy Division Staff White Paper – Staff Proposal on Avoided Costs and Locational Granularity of Transmission and Distribution Deferral Values
- D. 20-03-005 - Commission Decision Adopting Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values
- D.17-09-026 - Commission Decision on Track 1 Demonstration Projects A (Integration Capacity Analysis)
- D.16-01-044 - Commission Decision Adopting Successor to Net Energy Metering Tariff
- D.15-09-022 - Commission Decision Adopting an Expanded Scope, A Definition, And A Goal for The Integration of Distributed Energy Resources

Next Steps and Close

- Informal comments on the Draft Research Plans can be submitted to PDA by EOD September 5th
- Slides and recording will be shared with Stakeholders via the Service List (the PDA link to the draft research plans has already been shared)
- Energy Division staff anticipate the results of the T&D Study to be incorporated into the 2028 ACC Update. Outcomes from these studies will not meet the required timeline for the 2026 ACC Update

Questions?

Thank you for your time and attention

California Public Utilities Commission