Agenda
Unified Planning Assumptions & Study Plan

Elizandra Casillas
Stakeholder Engagement and Policy Specialist

2022-2023 Transmission Planning Process Stakeholder Meeting
February 28, 2022

2022-2023 Transmission Planning Process Stakeholder Meeting - Agenda

Topic	Presenter
Introduction	Elizandra Casillas
Overview & Key Issues	Binaya Shrestha
Reliability Assessment	Preethi Rondla
Policy Assessment	Nebiyu Yimer
Economic Assessment	Yi Zhang
Frequency Response	Chris Fuchs
Wrap-up & Next Steps	Elizandra Casillas

Overview
Unified Planning Assumptions & Study Plan

Binaya Shrestha
Manager, Regional Transmission North

2022-2023 Transmission Planning Process Stakeholder Meeting
February 28, 2022

2022-2023 Transmission Planning Process

January 2022 — April 2022 — March 2023

Phase 1 – Develop detailed study plan

State and federal policy

CEC - Demand forecasts

CPUC - Resource forecasts and common assumptions with procurement processes

Other issues or concerns

Phase 2 - Sequential technical studies

- Reliability analysis
- Renewable (policy-driven) analysis
- Economic analysis

Publish comprehensive transmission plan with recommended projects

Phase 3 Procurement

CAISO Board for approval of transmission plan

California ISO

2022-2023 Transmission Plan Milestones

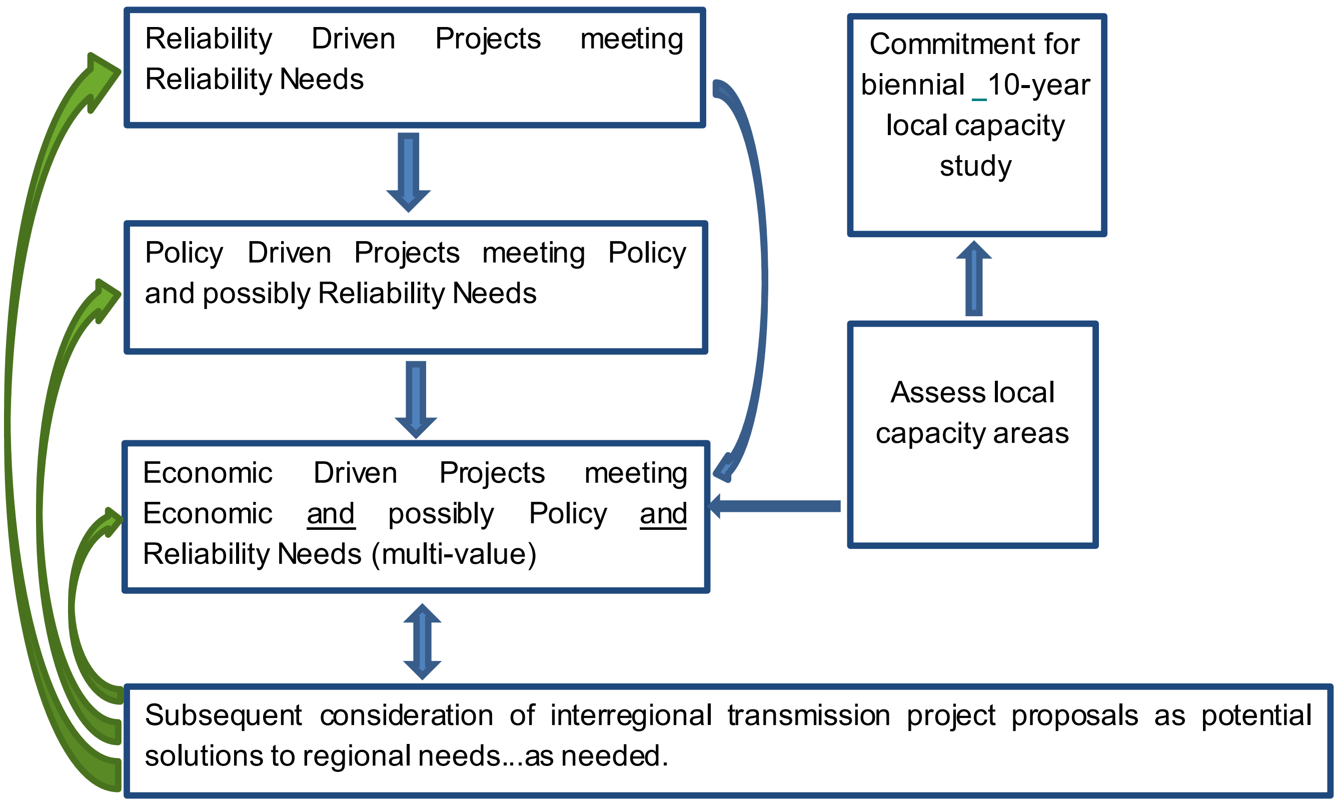
- Draft Study Plan posted on February 21
- Stakeholder meeting on Draft Study Plan on February 28
  - Comments to be submitted by March 14
- Final Study Plan to be posted on March 31
- Preliminary reliability study results to be posted on August 15
- Stakeholder meeting on September 27 and 28
  - Comments to be submitted by October 12
- Request window closes October 15
- Preliminary policy and economic study results on November 17
  - Comments to be submitted by December 5
- Draft transmission plan to be posted on January 31, 2023
- Stakeholder meeting in February
  - Comments to be submitted within two weeks after stakeholder meeting
- Revised draft for approval at March Board of Governor meeting

2022-2023 Transmission Planning Process Key Inputs

- Portfolio included in CPUC Decision 22-02-004 for use in CAISO 2022-2023 transmission planning process
  https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=451412947
  – Baseline portfolio
    - Reliability, Policy and Economic Assessments
  – Sensitivity portfolio
    - For special study

- 2021 IEPR California Energy Demand forecast adopted by the CEC on January 26, 2022
  https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1

Studies are coordinated as a part of the transmission planning process



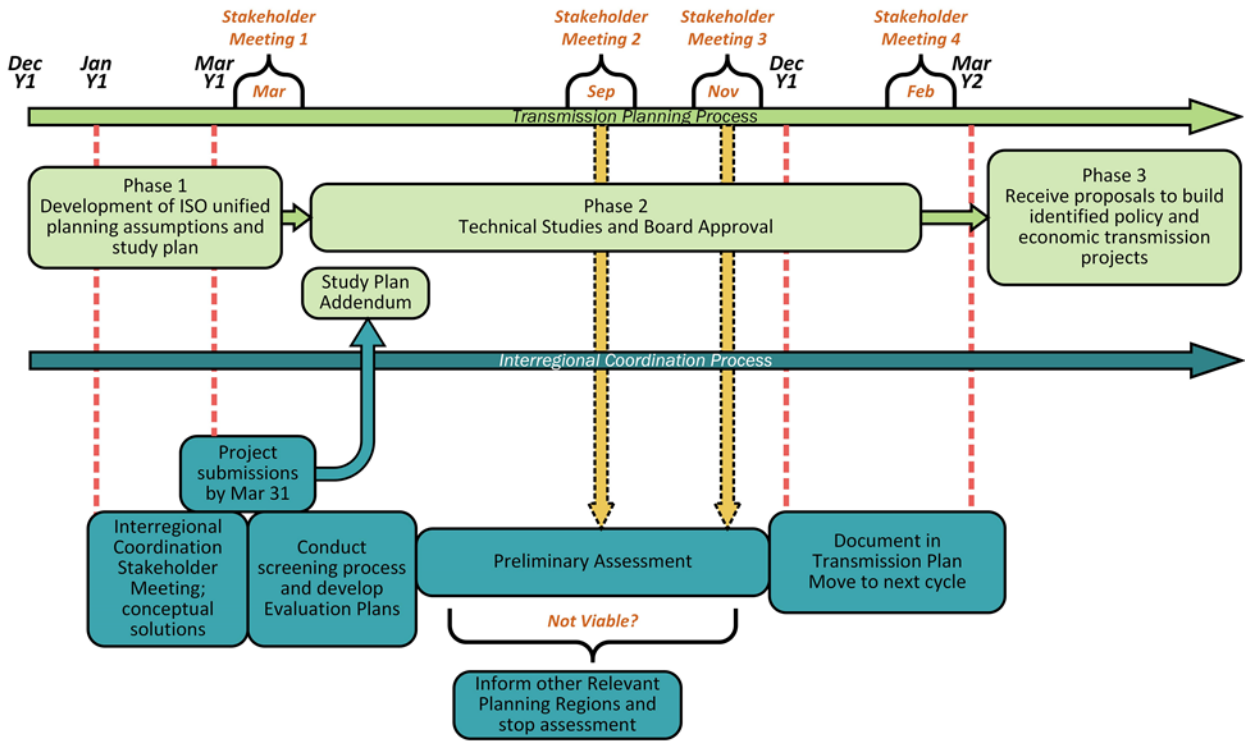
2022-2023 Transmission Plan Study Plan

- Reliability Assessment to identify reliability-driven needs
- Policy Assessment to identify policy-driven needs
- Economic Planning Study to identify needed economically-driven elements
- Other Studies
  - Local Capacity Technical studies
    - Long-term local capacity technical study will be conducted
  - Maximum Import Capability expansion requests
  - Long-term Congestion Revenue Rights
  - Frequency response

Interregional Transmission Coordination - Year 1 of 2

- Open window (January 1 through March 31) for proposed interregional transmission projects to be submitted to the CAISO for consideration in the CAISO's 2022-2023 TPP planning cycle
- The CAISO will host a joint western planning regions' stakeholder call on March 4, 2022.

Year 1 (Even Year) - Interregional Coordination Process



http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

Maximum Import Capability Expansion Requests

- Maximum import capability expansion requests are to be submitted with the comments on the draft study plan by March 14, 2022
  - Must identify the intertie(s) (branch group(s)) that require expansion
  - For an LSE, the request must include information about existing resource adequacy contracts
  - For new transmission owners or other market participants the request must include information on contractual arrangements or other evidence of financial commitments the requestor has already made in order to serve load or meet resource adequacy requirements within the CAISO balancing authority area
  - The quality of the data must be sufficient for the CAISO to make a determination about the validity of such request
  - The CAISO will maintain confidentiality of data provided except for the requestor name, intertie (branch group) and the MW quantity of the expansion request

Maximum Import Capability Expansion Requests (continued)

- The CAISO will evaluate each maximum import capability expansion request in order to establish if the submitting entity meets the criteria
- The descriptions of valid maximum import capability requests will be included in the final study plan
- The valid MIC expansion requests with the policy driven MIC expansion and the total of the two will be used to identify all branch groups that do not have sufficient Remaining Import Capability to cover both the valid MIC expansion requests and the policy driven MIC expansion

Special Studies

High Electrification Scenario

- To evaluate the potential reliability impacts to the transmission facilities based on a high electrification scenario.
  - The CEC, in collaboration with the CPUC and the CAISO, is developing a demand scenario that places a greater emphasis on electrification than is embedded within the CEC's 2021 IEPR energy demand forecast.
  - The CPUC will also be developing a resource portfolio based upon the high electrification scenario.
  - The CEC and CPUC are targeting to provide the high electrification scenario load forecast and resource portfolio to the CAISO by June 1, 2022.
  - The CAISO will engage stakeholders when further details are available.

Special Studies

Reduced Reliance on Aliso Canyon Gas Storage

- Transmission study to evaluate the potential reliability impacts to the transmission facilities in the LA Basin and to some extent the San Diego-Imperial Valley local capacity areas in the CAISO Balancing Authority Area due to strong interaction between these two areas.
- The CAISO will work with the CPUC to obtain potential ranges of gas-fired generation capacity impacts.
- The CAISO will engage stakeholders when further details are available.

20-Year Transmission Outlook - Update

- The draft 20-Year Transmission Outlook will be finalized in March in parallel with the 2021-2022 Transmission Plan

- After finalizing, the CAISO intends to:
  - Discuss the findings and garner feedback in ongoing SB 100 processes and perhaps additional stakeholder sessions
    - Presented at joint agency workshop for SB 100 resource build – analysis of land use implications on February 22, 2022

      https://www.energy.ca.gov/event/workshop/2022-02/joint-agency-workshop-plan-senate-bill-100-resource-build-analysis-land-use
  - Collect input on issues and parameters that could be considered and refined in a future outlook development cycle – thinking about 2023
  - Provide industry an update on the 20-Year Outlook activities and communicate intentions going forward, by year end.

Study Information

- Final Study Plan will be posted on 2022-2023 transmission planning process webpage on March 31st
  http://www.caiso.com/planning/Pages/TransmissionPlanning/2022-2023TransmissionPlanningProcess.aspx

- Base cases will be posted on the Market Participant Portal (MPP)
  - For reliability assessment in Q3

- Market notices will be posted in the Daily Briefings to notify stakeholders of meetings and any relevant information
  http://www.caiso.com/dailybriefing/Pages/default.aspx

Comments
2022-2023 TPP Draft Study Plan

- Comments due by end of day March 14, 2022 including:
  - Economic study requests and
  - Maximum Import Capability (MIC) expansion requests are to be submitted with comments

- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:

https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2022-2023-Transmission-planning-process

California ISO

Reliability Assessment
Unified Planning Assumptions & Study Plan

Preethi Rondla

2022-2023 Transmission Planning Process Stakeholder Meeting
February 28, 2022

Planning Assumptions

- Reliability Standards and Criteria
  - California ISO Planning Standards
  - NERC Reliability Criteria
    - TPL-001-5
      - Modified category P5 & R2.4.5 will be implemented in this cycle
    - NUC-001-3
  - WECC Regional Criteria
    - TPL-001-WECC-CRT-3.2

Planning Assumptions
(continued)

- Study Horizon
  - – 10 years planning horizon
    - near-term: 2024 to 2027
    - longer-term: 2028 to 2032

- Study Years
    - near-term: 2024 and 2027
    - longer-term: 2032

California ISO

Study Areas

- **Northern Area - Bulk**
- **PG&E Local Areas:**
  - Humboldt area
  - North Coast and North Bay area
  - North Valley area
  - Central Valley area
  - Greater Bay area:
  - Greater Fresno area;
  - Kern area;
  - Central Coast and Los Padres areas.
- **Southern Area – Bulk**
- **SCE local areas:**
  - Tehachapi and Big Creek Corridor
  - North of Lugo area
  - East of Lugo area;
  - Eastern area; and
  - Metro area
- **SDG&E area**
  - Bulk transmission
  - Sub-transmission
- **Valley Electric Association area**
- **ISO combined bulk system**

Use of Past Studies

- CAISO will continue to evaluate areas known to have no major changes compared to assumptions made in prior planning cycles for potential use of past studies. (TPL-R2.6)
- At a high level, the process will include three major steps :
  - Data collection
  - Evaluation of data change
  - Drawing conclusions based on judgment and evaluation collection
- Data collection and evaluation of extent of change will include following major categories:
  - Transmission data
  - Generation data
  - Load data
  - Applicable standards

Transmission Assumptions

- Transmission Projects
  - Transmission projects that the CAISO has approved will be modeled in the study base case
  - Canceled and on-hold projects will not be modeled
- Reactive Resources
  - Existing and planned reactive power resources will be modeled
- Protection Systems
  - Existing and planned RAS, safety nets, UVLS & UFLS will be modeled
  - Continue to include RAS models and work with PTOs to obtain remaining RAS models.
- Control Devices
  - Existing and Planned control devices will be modeled in the studies

Load Forecast Assumptions
Energy and Demand Forecast

- California Energy Demand Updated Forecast 2021-2032 adopted by California Energy Commission (CEC) on January 26, 2022 will be used:
  - Using the Mid Baseline LSE and Balancing Authority Forecast spreadsheets
  - Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Fuel Substitution (AAFS)
    - Consistent with CEC 2021 IEPR
    - Mid AAEE and mid AAFS will be used for system-wide studies
    - Low AAEE and mid plus AAFS will be used for local studies
  - CEC forecast information is available on the CEC website at:

https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-IEPR-03

Load Forecast Assumptions
Energy and Demand Forecast (continued)

- Load forecasts to be used for each of the reliability assessment studies.
  - 1-in-10 weather year, mid demand baseline case with low AAEE and mid plus AAFS load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the local capacity requirement (LCR) areas
  - 1-in-5 weather year, mid demand baseline case with mid AAEE and mid AAFS load forecast will be used for bulk system studies

Load Forecast Assumptions
Methodologies to Derive Bus Level Forecast

- The CEC load forecast is generally provided for the larger areas and does not provide the granularity down to the bus-level which is necessary in the base cases for the reliability assessment

- The local area load forecast are developed at the bus-level by the participating transmission owners (PTOs) .

- Descriptions of the methodologies used by each of the PTOs to derive bus-level load forecasts using CEC data as a starting point are included in the draft Study Plan.

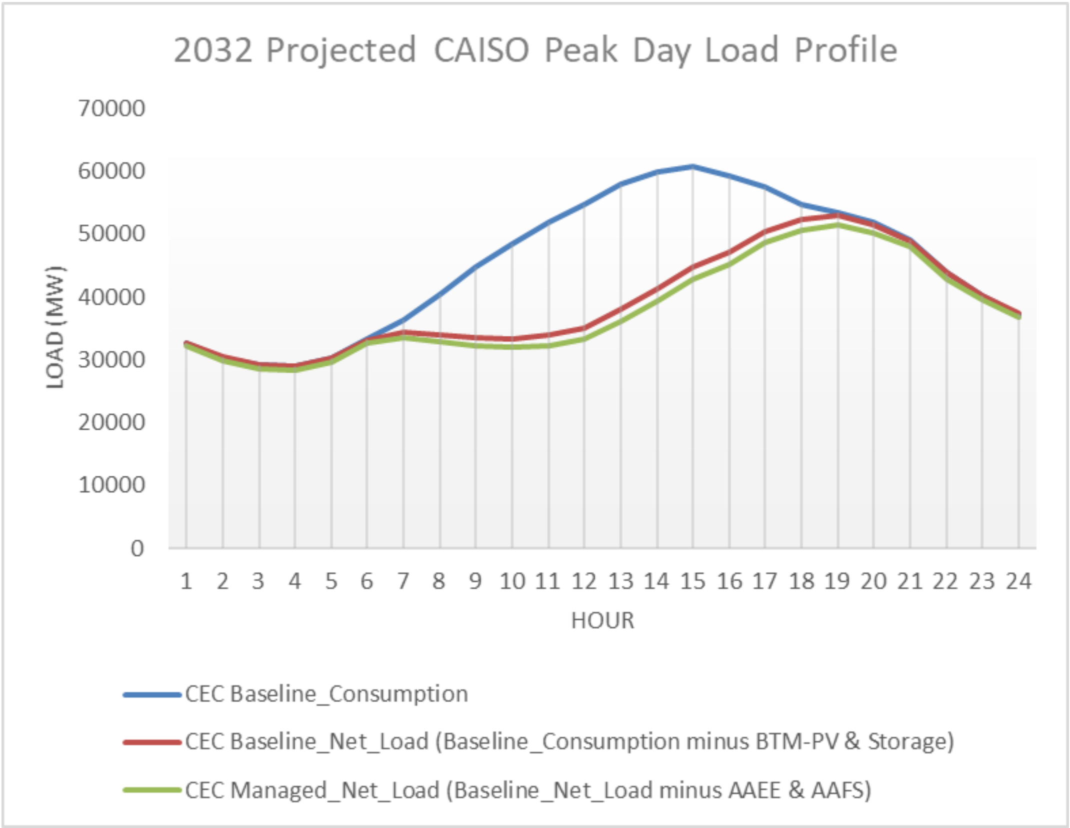
Load Forecast Assumptions

BTM-PV, BTM-Storage and AAEE

- Similar to previous cycles, BTM-PV will be modeled explicitly in the 2022-2023 TPP base cases.
  - Amount of the BTM-PV to be modeled will be based on 2021 IEPR data.
  - Location to model BTM-PV will be identified based on location of existing BTM-PV, information from PTO on future growth and BTM-PV capacity by forecast climate zone information from CEC.
  - Output of the BTM-PV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.
  - Composite load model CMPLDWG will be used to model the BTM-PV. DER_A model will be used for dynamic representation of BTM-PV.
- BTM-storage will not be modeled explicitly in 2022-2023 TPP base cases due to limitation within the GE PSLF tool to model more than one distributed resources behind each load and lack of locational information. However it will be accounted for by netting to the load.
- AAEE and AAFS will be modeled using the CEC provided bus-bar allocations and will be modeled as negative load.

Load Forecast Assumptions

BTM-PV, BTM-Storage, AAEE & AAFS impact on load profile



Supply Side Assumptions - Continued coordination with CPUC Integrated Resource Planning (IRP)

- CPUC Proposed Decision:
  https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M449/K173/449173804.PDF
  - Base portfolio (for Reliability, Policy and Economic Assessment)

- **Base portfolio** modeling assumptions to be used in 2022-2023 TPP:
  - CPUC Staff Report: Modeling Assumptions for the 2022-2023 TPP
    https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M434/K244/434244658.PDF

Generation Assumptions

- New Generation Modeling
  - Level 1: Under construction (for Years 1-5 study case with applicable in-service dates)
  - Level 2: Regulatory approval but not yet under construction (i.e., having Power Purchase Agreement approved by the CPUC or other regulatory agencies with applicable in-service dates for Year 5)
  - Level 3: CPUC Base Portfolio generation, or planned resources in the IRP (for entity outside of California) for the 10-year study case (or for 6-10 year case with applicable in-service dates)
- Retired generation is modeled offline and disconnected in appropriate study years

Generation Assumptions

Distribution connected resources modeling

- Behind-the-meter generators: Model explicitly as component of load
- In-front-of-the-meter with resource ID: Model as individual generator
- In-front-of-the-meter without resource ID:
  - Model as individual generator if >10 MW,
  - Model as aggregate if <10 MW for same technology

Generation Assumptions
Generation Retirements

- <u>Nuclear Retirements</u>
  - Diablo Canyon will be modeled off-line based on the OTC compliance date
- <u>Once Through Cooled Retirements</u>
  - Separate slide below for OTC assumptions
- <u>Renewable and Hydro Retirements</u>
  - Assumes these resource types stay online unless there is an announced retirement date.

Generation Assumptions

OTC Generation

- Modeling based on the SWRCB's compliance schedule with the following exceptions:
  - Generating units that are repowered, replaced or have firm plans to connect to acceptable cooling technology
  - Generating units that have been approved for compliance schedule extension to meet CAISO system capacity need for 2021-2023 timeframe
  - Generating units with approved Track 2 mitigation plan

Preferred Resources

- Demand Response
  - Long-term transmission expansion studies may utilize fast-response DR and slow-response PDR if it can be dispatched pre-contingency.
  - DR that can be relied upon participates, and is dispatched from, the ISO market in sufficiently less than 30 minutes (implies that programs may need 20 minutes response time to allow for other transmission operator activities) from when it is called upon
  - DR capacity will be allocated to bus-bar using the method defined in D.12-12-010, or specific bus-bar allocations provided by the IOUs.
  - The DR capacity amounts will be modeled offline in the initial reliability study cases and will be used as potential mitigation in those planning areas where reliability concerns are identified.

Preferred Resources

- Energy Storage
  - Existing, under construction and/or approved procurement status energy storage projects.
  - Behind-the-meter energy storage will be netted to load due to tool limitation

Major Path Flows and Interchange

Northern area (PG&E system) assessment

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4000	Summer Peak
PDCI (N-S)	3210	
Path 66 (N-S)	4800	
Path 15 (N-S)	-5400	Spring Off Peak
Path 26 (N-S)	-3000	
PDCI (N-S)	-3100	
Path 66 (N-S)	-975	Winter Peak

Southern area (SCE & SDG&E system) assessment

Path	Transfer Capability/ SOL (MW)	Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
Path 26 (S-N)	3,000	0 to 3,000	Spring Off Peak
PDCI (N-S)	3210	3210	Summer Peak
PDCI (S-N)	975[40]	975	Spring Off Peak
West of River (WOR) (E-W	12,150	0 to 11,200	Summer Peak
East of River (EOR) (E-W)	10,100	1400 to 10,100	Summer Peak
East of River (EOR) (W-E)		2000 to 7500	Summer peak/Spring Off Peak
San Diego Import	2765~3565	2,400 to 3,500	Summer Peak
Path 45 (N-S)	600	0 to 600	Summer Peak
Path 45 (S-N)	800	0 to 300	Spring Off Peak

Study Scenarios - *Base Scenarios*

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2024	2027	2032
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak Winter Off-Peak
Humboldt	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak
SCE Metro Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak

Study Scenarios - *Baseline Scenarios Definition and Renewable Dispatch for System-wide Cases*

PTO	Scenario	Day/Time			BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
		2024	2027	2032	2024	2027	2032	2024	2027	2032	2024	2027	2032	2024	2027	2032
PG&E	Summer Peak	7/25 HE 19	See CAISO	See CAISO	5%	See CAISO	See CAISO	2%	See CAISO	See CAISO	56%	See CAISO	See CAISO	100%	See CAISO	See CAISO
PG&E	Spring Off Peak	4/24 HE 20	See CAISO	See CAISO	0%	See CAISO	See CAISO	0%	See CAISO	See CAISO	49%	See CAISO	See CAISO	70%	See CAISO	See CAISO
PG&E	Winter Off peak	N/A	N/A	11/9 HE 5	N/A	N/A	0%	N/A	N/A	0%	N/A	N/A	12%	N/A	N/A	46%
PG&E	Winter peak	12/09 HE 19	12/14 HE 19	12/9 HE 19	0%	0%	0%	0%	0%	0%	15%	13%	13%	74%	76%	78%
SCE	Summer Peak	9/3 HE 16	9/7 HE 17	9/7 HE 19	47%	24%	0%	51%	21%	0%	15%	19%	40%	100%	100%	100%
SCE	Spring Off Peak	4/24 HE 20	See CAISO	See CAISO	0%	See CAISO	See CAISO	0%	See CAISO	See CAISO	46%	See CAISO	See CAISO	66%	See CAISO	See CAISO
SDG&E	Summer Peak	9/4 HE 19	9/2 HE 19	9/4 HE 19	0%	0%	0%	1%	0%	0%	25%	33%	33%	100%	100%	100%
SDG&E	Spring Off Peak	5/28 HE 20	See CAISO	See CAISO	0%	See CAISO	N/A	0%	See CAISO	N/A	61%	See CAISO	N/A	74%	See CAISO	N/A
VEA	Summer Peak	9/3 HE 16	9/7 HE 17	9/7 HE 19	N/A	N/A	N/A	37%	14%	0%	N/A	N/A	N/A	100%	100%	100%
VEA	Spring Off Peak	4/24 HE 20	See CAISO	See CAISO	N/A	N/A	N/A	0%	See CAISO	See CAISO	N/A	N/A	N/A	66%	See CAISO	See CAISO

Study Scenarios - *Sensitivity Studies*

Sensitivity Study	Near-term Planning Horizon		Long-term Planning Horizon
	2024	2027	2032
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	
Off peak with heavy renewable output, different import level or storage charging	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-	
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-	
Summer Peak with forecasted load addition	VEA Area	VEA Area	
Summer Off peak with heavy renewable output	-	VEA Area	

Study Scenarios - *Sensitivity Scenario Definitions and Renewable Generation Dispatch*

PTO	Scenario	Starting Baseline Case	BTM-PV		Transmission Connected PV		Transmission Connected Wind		Comment
			Baseline	Sensitivity	Baseline	Sensitivity	Baseline	Sensitivity	
PG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2024 Summer Peak	5%	99%	2%	99%	56%	62%	Solar and wind dispatch increased to 20% exceedance values
	Off peak with heavy renewable output, import level or storage charging	2024 Spring Off-peak	0%	TBD	0%	TBD	20%	TBD	TBD
	Summer Peak with high CEC forecasted load	2027 Summer Peak	6%	6%	0%	0%	32%	32%	Load increased by turning off AAEE
SCE	Summer Peak with heavy renewable output and minimum gas generation commitment	2024 Summer Peak	46%	91%	51%	99%	19%	67%	Solar and wind dispatch increased to 20% exceedance values
	Off peak with heavy renewable output, import level or storage charging	2024 Spring Off-peak	0%	TBD	0%	TBD	48%	TBD	TBD
	Summer Peak with high CEC forecasted load	2027 Summer Peak	0%	0%	0%	0%	40%	40%	Load increased per CEC high load scenario
SDG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2024 Summer Peak	0%	96%	0%	96%	33%	51%	Solar and wind dispatches increased to 20% exceedance values
	Off peak with heavy renewable output, import level or storage charging	2024 Spring Off-peak	0%	TBD	0%	TBD	68%	TBD	TBD
	Summer Peak with high CEC forecasted load	2027 Summer Peak	0%	0%	0%	0%	25%	25%	Load increased per CEC high load scenario
VEA	Summer Peak with forecasted load addition	2024 Summer Peak			51%	51%			Load increase reflect future load service request
	Off-peak with heavy renewable output	2027 Spring Off-peak			0%	96%			Modeled active GIDAP projects in the queue
	Summer Peak with forecasted load addition	2027 Summer Peak			21%	21%			Load increase reflect future load service request

Study Base Cases

- WECC base cases will be used as the starting point to represent the rest of WECC

Study Year	Season	WECC Base Case	Year Published
2024	Summer Peak	2025 Heavy Summer 3	10/29/2021
	Winter Peak	2022-23 Heavy Winter 3	1/7/2022
	Spring Off-Peak	2022 Heavy Spring 1	3/5/2021
2027	Summer Peak	2027 Heavy Summer 1	3/29/2021
	Winter Peak	2026-27 Heavy Winter 2	3/31/2021
	Spring Off-Peak	2024 Light Spring 1	5/1/2020
2032	Summer Peak	2032 Heavy Summer 1	8/13/2021
	Spring Off-Peak	2033 Light Spring 1	12/6/2021

Contingencies

- **Normal conditions (P0)**

- **Single contingency (Category P1)**
  - The assessment will consider all possible Category P1 contingencies based upon the following:
    - Loss of one generator (P1.1)
    - Loss of one transmission circuit (P1.2)
    - Loss of one transformer (P1.3)
    - Loss of one shunt device (P1.4)
    - Loss of a single pole of DC lines (P1.5)

- **Single contingency (Category P2)**
  - The assessment will consider all possible Category P2 contingencies based upon the following:
    - Loss of one transmission circuit without a fault (P2.1)
    - Loss of one bus section (P2.2)
    - Loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
    - Loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)

Contingencies
(continued)

- **Multiple contingency (Category P3)**
  - The assessment will consider the Category P3 contingencies with the loss of a *generator unit* followed by system adjustments and the loss of the following:
    - Loss of one generator (P3.1)
    - Loss of one transmission circuit (P3.2)
    - Loss of one transformer (P3.3)
    - Loss of one shunt device (P3.4)
    - Loss of a single pole of DC lines (P3.5)

- **Multiple contingency (Category P4)**
  - The assessment will consider the Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5) attempting to clear a fault on one of the following:
    - Loss of one generator (P4.1)
    - Loss of one transmission circuit (P4.2)
    - Loss of one transformer (P4.3)
    - Loss of one shunt device (P4.4)
    - Loss of one bus section (P4.5)
    - Loss of a bus-tie-breaker (P4.6)

Contingencies
(continued)

- **Multiple contingency (Category P5)**
  - The assessment will consider the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant component of protection system protecting the faulted element to operate as designed, for one of the following:
    - Loss of one generator (P5.1)
    - Loss of one transmission circuit (P5.2)
    - Loss of one transformer (P5.3)
    - Loss of one shunt device (P5.4)
    - Loss of one bus section (P5.5)
- **Multiple contingency (Category P6)**
  - The assessment will consider the Category P6 contingencies with the loss of two or more (non-generator unit) elements with system adjustment between them, which produce the more severe system results.
- **Multiple contingency (Category P7)**
  - The assessment will consider the Category P7 contingencies for the loss of a common structure as follows:
    - Any two adjacent circuits on common structure14 (P7.1)
    - Loss of a bipolar DC lines (P7.2)

Contingency Analysis *(continued)*

- **Extreme contingencies (TPL-001-5)**
  - As a part of the planning assessment the ISO assesses Extreme Event contingencies;
    - Analysis will be included in TPP if requirements drive the need for mitigation plan.

Technical Studies

- The planning assessment will consist of:
  - – Power Flow Contingency Analysis
  - – Post Transient Analysis
    - Post Transient Thermal Analysis
    - Post Transient Voltage Stability Analysis
      - – Post Transient Voltage Deviation Analysis
      - – Voltage Stability and Reactive Power Margin Analysis
  - – Transient Stability Analysis

Corrective Action Plans

- ISO will identify the need for any transmission additions or upgrades required to ensure System reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards.
  – ISO in coordination with PTO and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as:
    - acceleration or expansion of existing projects,
    - demand-side management,
    - special protection systems,
    - generation curtailment,
    - interruptible loads,
    - storage facilities; or
    - reactive support

Policy-driven Assessment
Unified Planning Assumptions & Study Plan

Nebiyu Yimer
Senior Advisor, Regional Transmission South

2022-2023 Transmission Planning Process Stakeholder Meeting
February 28, 2022

Agenda

- Policy-driven assessment objectives and scope
- Description of portfolios transmitted by the CPUC
- Deliverability assessment methodology
- Next steps

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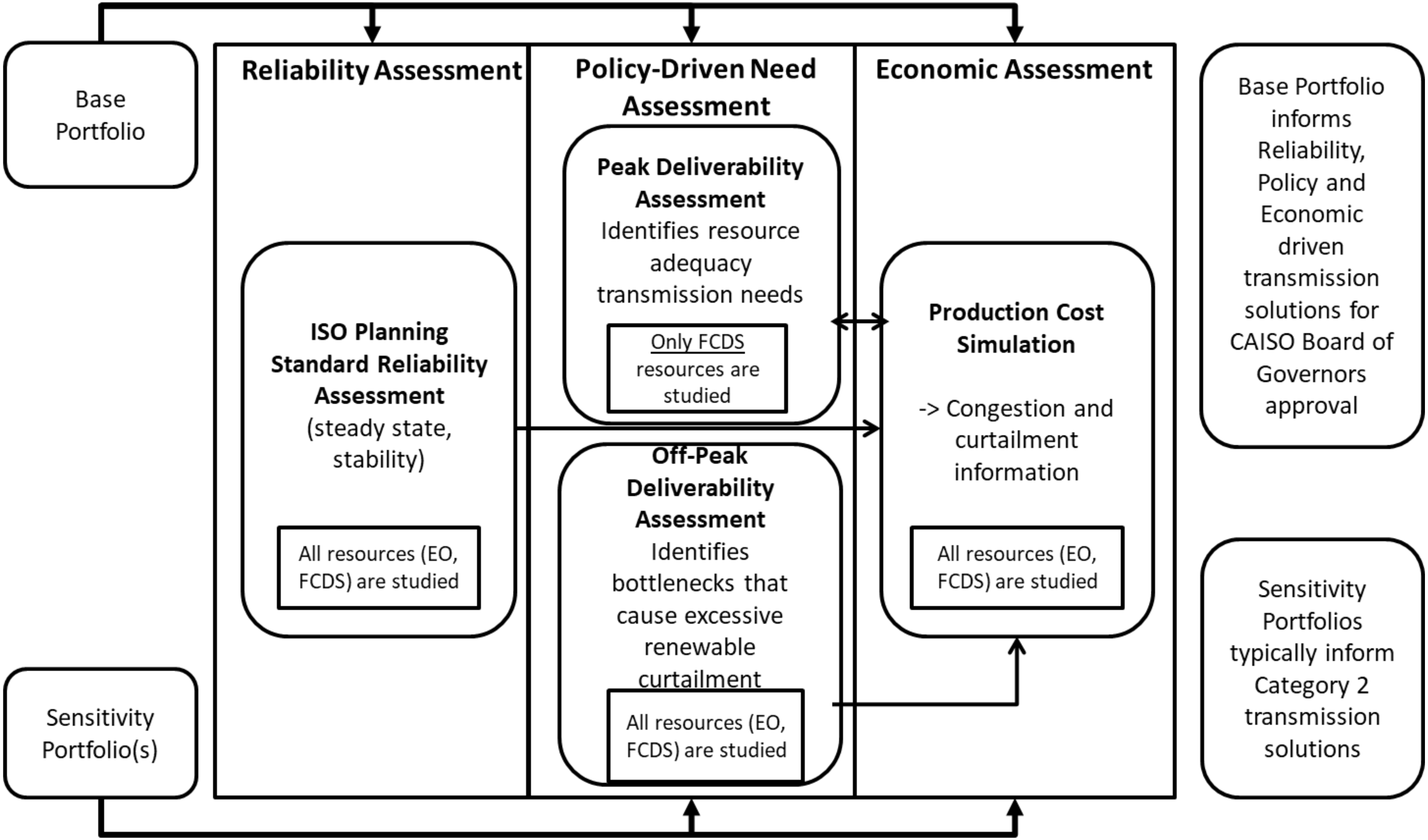
Objectives and scope

- Overarching objective is to ensure alignment between resource planning (CPUC) and transmission planning (CAISO)
- Deliverability assessment (on-peak) supports deliverability of FCDS resources selected to meet resource adequacy needs
- Production cost simulation supports the economic delivery of renewable energy over the course of all hours of the year
- Reliability assessment and off-peak deliverability assessment are used to identify constraints for further evaluation using production cost simulation
- Assessment is used to identify transmission upgrades or other solutions needed to achieve objectives
- Gain further insights to inform future portfolio development

Overview of the policy-driven assessment



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Resources portfolios for the 2022-2023 TPP

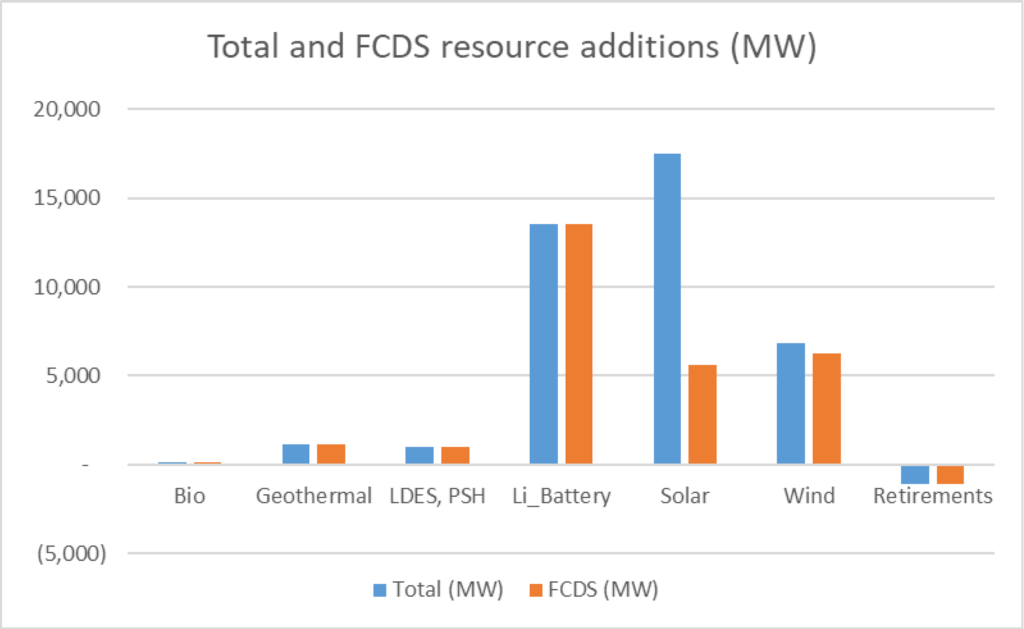
- The 2022-2023 TPP policy-driven study will be based on a base portfolio and potentially a sensitivity portfolio
- As the base portfolio, the CPUC transmitted a PSP portfolio based on the 38 MMT GHG target by 2030 and the 2020 IEPR demand forecast utilizing the high electric vehicle assumptions. The portfolio data provided includes
  - Baseline resource assumptions,
  - The incremental resource portfolio selected to meet GHG and reliability targets complete with bus-bar mapping,
  - Age-based retirement assumptions and
  - Transmission capability calculations to identify exceedances
- The Commission also delegated to its staff the development of a policy-driven sensitivity portfolio in consultation with the CEC and CAISO based on a 30 MMT GHG target, and associated busbar mapping, if it is determined by Commission staff to be feasible within the next few months.

CPUC portfolio documentation for the 2022-2023 TPP

- Decision adopting the 2021 Preferred System Plan:
  https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF
- Modeling Assumptions for the 2022-2023 TPP
  https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF
- Final busbar mapping results and transmission limit calculation for the base portfolio
  ftp://ftp.cpuc.ca.gov/energy/modeling/BusbarMapping_Dashboard_38MMT_V2022_02_08.xlsx
  (particularly the 'FinalMapping_bySub' and '2_Tx_Calculator_R5' tabs)
- Baseline resource assumptions
  ftp://ftp.cpuc.ca.gov/energy/modeling/workbook:Baseline_Reconciliation_V2022_02_08.xlsx
- Thermal Age Based Retirements Assumptions
  ftp://ftp.cpuc.ca.gov/energy/modeling/Thermal%20Age%20Based%20Retirements%20Assumptions_V2021_10_15.xlsx

Total and FCDS base portfolio resource additions

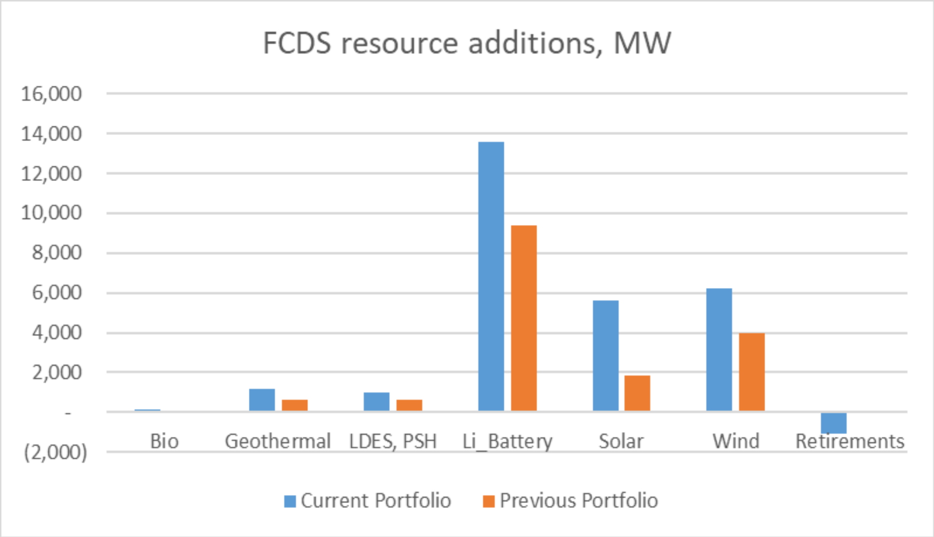
Resource Type	Total (MW)	FCDS (MW)
Biomass/Biogas	134	134
Distributed Solar	125	125
Geothermal	1,159	1,159
In-State Wind	3,032	2,533
LDES, PSH	1,000	1,000
Li_Battery	13,564	13,564
Offshore Wind	1,708	1,588
OOS Wind, Ext Tx	610	610
OOS Wind, New Tx	1,500	1,500
Solar	17,379	5,490
Retirements	(1,055)	(1,055)
Grand Total	**39,156**	**26,647**



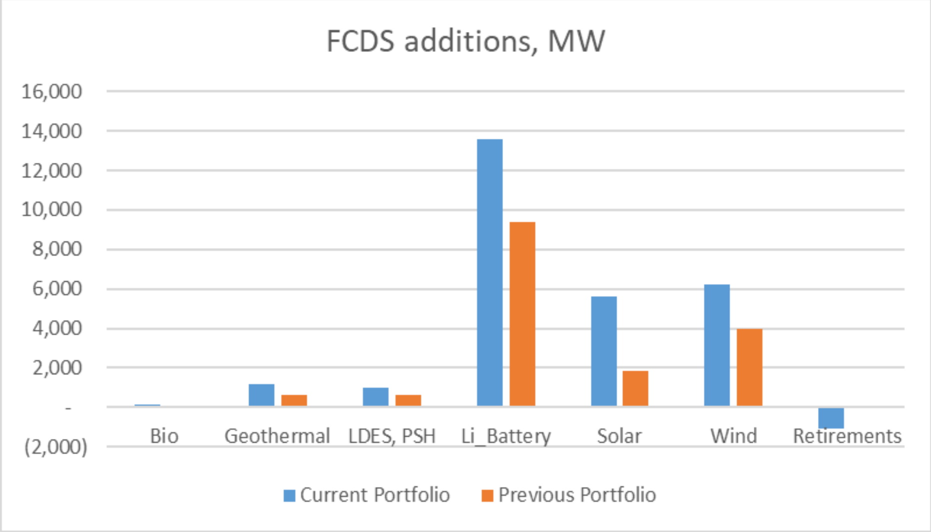
In addition, the portfolio includes 441 MW of shed demand response for which bus-bar mapping is not available

Comparison of current and previous base portfolios

	Resource additions - Total	
Resource Type	Current Portfolio	Previous Portfolio
Bio	134	-
Geothermal	1,159	651
LDES, PSH	1,000	627
Li_Battery	13,564	9,368
Solar	17,504	13,044
Wind	6,850	4,005
Retirements	(1,055)	-
Grand Total	**39,156**	**27,695**



	Resource additions - FCDS	
Resource Type	Current Portfolio	Previous Portfolio
Bio	134	-
Geothermal	1,159	651
LDES, PSH	1,000	627
Li_Battery	13,564	9,368
Solar	5,615	1,832
Wind	6,231	3,971
Retirements	(1,055)	-
Grand Total	**26,647**	**16,449**



Non-storage resources by location

RESOLVE Resource Name	Resource Type	Current Portfolio 38 MMT Base Case 2032 FCDS (MW)	Current Portfolio 38 MMT Base Case 2032 EODS (MW)	Prior Portfolio 46 MMT Base Case 2031 FCDS (MW)	Prior Portfolio 46 MMT Base Case 2031 EODS (MW)
InState Biomass	Biomass/Biogas	134	-	-	-
Solano_Geothermal	Geothermal	79	-	51	-
Northern_California_Geothermal	Geothermal	-	-	-	-
Inyokern_North_Kramer_Geothermal	Geothermal	40	-	-	-
Southern_Nevada_Geothermal	Geothermal	440	-	-	-
Riverside_Palm_Springs_Geothermal	Geothermal	-	-	-	-
Greater_Imperial_Geothermal	Geothermal	600	-	600	-
Distributed Solar	Solar	125	-	-	-
Greater_LA_Solar	Solar	-	1,503	-	1,003
Northern_California_Solar	Solar	-	-	-	-
Southern_PGAE_Solar	Solar	1,022	1,781	783	1,340
Tehachapi_Solar	Solar	1,751	3,002	395	3,282
Greater_Kramer_Solar	Solar	385	1,071	305	196
Southern_NV_Eldorado_Solar	Solar	770	1,946	348	2,491
Riverside_Solar	Solar	862	1,106	-	504
Arizona_Solar	Solar	600	1,281	-	1,849
Imperial_Solar	Solar	100	200	-	548
Northern_California_Wind	Wind	305	351	767	-
Solano_Wind	Wind	272	148	462	-
Humboldt_Wind	Wind	-	-	-	34
NW_Ext_Tx_Wind	OOS Wind	-	-	530	-
Kern_Greater_Carrizo_Wind	Wind	60	-	20	-
Carrizo_Wind	Wind	287	-	187	-
Central_Valley_North_Los_Banos_Wind	Wind	186	-	173	-
Tehachapi_Wind	Wind	275	-	275	-
Southern_Nevada_Wind	Wind	442	-	-	-
Wyoming_Wind/Idaho_Wind	OOS Wind, New Tx	1,062	-	1,062	-
Riverside_Palm_Springs_Wind	Wind	106	-	-	-
New_Mexico_Wind	OOS Wind, New Tx	438	-	-	-
SW_Ext_Tx_Wind	OOS Wind, Ext Tx	610	-	-	-
Baja_California_Wind	Wind	600	-	495	-
Humboldt_Bay_Offshore_Wind	Offshore Wind	-	120	-	-
Morro_Bay_Offshore_Wind	Offshore Wind	1,588	-	-	-
Diablo_Canyon_Offshore_Wind	Offshore Wind	-	-	-	-
Total Non-Storage		**13,139**	**12,509**	**6,453**	**11,247**

Storage resources by location

RESOLVE Resource Name	Resource Type	Current Portfolio 38 MMT Base Case		Prior Portfolio 46 MMT Base Case	
		2032 FCDS (MW)	2032 EODS (MW)	2031 FCDS (MW)	2031 EODS (MW)
Greater_LA_Li_Battery	Li_Battery	2,861	-	2,710	-
Northern_California_Li_Battery	Li_Battery	607	-	314	-
Southern_PGAE_Li_Battery	Li_Battery	1,624	-	576	-
Tehachapi_Li_Battery	Li_Battery	3,051	-	3,227	-
Greater_Kramer_Li_Battery	Li_Battery	869	-	176	-
Southern_NV_Eldorado_Li_Battery	Li_Battery	1,236	-	700	-
Riverside_Li_Battery	Li_Battery	1,608	-	-	-
Arizona_Li_Battery	Li_Battery	759	-	695	-
Imperial_Li_Battery	Li_Battery	50	-	-	-
San_Diego_Li_Battery	Li_Battery	899	-	970	-
Total Battery		**13,564**	**-**	**9,368**	**-**
Riverside_West_Pumped_Storage	LDES	-	-	313	
Tehachapi_LDES	LDES	500	-	-	-
Riverside_East_Pumped_Storage	LDES	-	-	-	-
San_Diego_Pumped_Storage	LDES	500	-	314	-
Total LDES		**1,000**	**-**	**627**	**-**

Additional guidance from the CPUC

- CAISO should consult the CPUC before moving forward with any new policy-driven transmission upgrades associated specifically with storage mapping in this planning cycle
- To the extent that storage resources are required for mitigation of transmission issues identified in the CAISO's 2021-2022 Transmission Plan, CPUC staff would expect to coordinate with CAISO to enable small adjustments in the CPUC's mapping of storage resources to allow for the inclusion of these storage resources in the CAISO's analysis of the 2022-2023 TPP portfolios.

Agenda

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On-peak deliverability assessment

- Assessment examines deliverability of portfolio resources selected as FCDS in accordance with the on-peak deliverability methodology

- Identifies transmission upgrades or other solutions needed to ensure deliverability of FCDS renewable portfolio resources
  - Other alternatives to be considered include: RAS and removing undeliverable portfolio battery storage

- Provides further insights to inform future portfolio development

Study scenarios in on-peak deliverability assessment

- Highest system need (HSN) scenario
  - Represents the scenario when capacity shortage is most likely to occur
  - Transmission upgrades identified for the base portfolio are recommended as policy driven upgrades

- Secondary system need (SSN) scenario
  - Represents the scenario when capacity shortage risk increases if variable resources are not deliverable during periods when the system depends on their high output for resource adequacy.
  - Transmission upgrades identified for the base portfolio will go through a comprehensive economic, policy, and reliability benefit analysis to be considered for approval as a policy driven or economic upgrade.

Modeling assumptions for HSN scenario

Selected Hours	HE18 ~ 22 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in CAISO summer assessment)
Load	1-in-5 peak sale forecast by CEC
Non-Intermittent Resources	Study amount set to highest summer month Qualifying Capacity in last three years
Intermittent Resources	Study amount set to 20% exceedance level during the selected hours
Import	MIC data with expansion approved in TPP

Modeling assumptions for SSN scenario

Select Hours	HE15 ~ 17 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in CAISO summer assessment)
Load	1-in-5 peak sale forecast by CEC adjusted to peak consumption hour
Non-Intermittent Generators	Study amount set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Study amount set to 50% exceedance level during the selected hours, but no lower than the average QC ELCC factor during the summer months
Import	Highest import schedules for the selected hours

On-peak assessment maximum resource dispatch

Resource type	HSN			SSN		
	SDG&E	SCE	PG&E	SDG&E	SCE	PG&E
Solar	3.0%	10.6%	10.0%	40.2%	42.7%	55.6%
Wind	33.7%	55.7%	66.5%	11.2%	20.8%	16.3%
OOS Wind	67%			35%		
Morro Bay OSW	100%			49%		
Energy storage	100% or 4-hour equivalent if duration is < 4-hour					
Non-Intermittent resources	100%					

Off-peak deliverability assessment

- Used to identify transmission constraints that would result in excessive renewable curtailment in accordance with the off-peak deliverability methodology
- Off-peak deliverability constraints are identified if the following adjustments do not alleviate the overload:
  - Dispatching existing energy storage in charging mode
  - Turning off thermal generators contributing to the overload
  - Reducing imports contributing to the constraint to the level required to support out-of-state renewables in the RPS portfolios
- Potential transmission upgrades needed to mitigate off-peak deliverability constraints are identified
  - Other alternatives to be considered include: RAS and adding new battery storage (subject to on-peak deliverability constraints)
- The constraints and the identified transmission upgrades are considered as candidates for a more thorough evaluation using production cost simulation

Modeling assumptions in off-peak deliverability assessment

Load	55% ~ 60% of summer peak load
Imports	~6000 MW total
System-Wide Generator Dispatch Level	
Wind	44%
Solar	68%
Energy Storage	0
Hydro	30%
Thermal	15%

Increase Local Area Renewable Output

- After balancing load and resource under the system-wide conditions, the renewable generation in a local study area is increased to identify transmission constraints.
- General local study areas include
  - PG&E : North, Fresno and Kern
  - SCE/VEA/GWL/DCRT: Northern, North of Lugo, East of Pisgah, Eastern
  - SDGE: Inland and East of Miguel
- Off-peak deliverability assessment is performed for each study area separately.

Study Area Wind/Solar Dispatch Assumptions

- The study area wind/solar dispatch assumptions are based on the 90% energy production level of existing generators inside the study area.
- If more than 70% of the study area capacity is wind, then the study area is deemed a wind area; otherwise it is treated as a solar area.

Wind/Solar Dispatch Assumptions in Wind Area

	Wind	Solar
SDG&E	69%	68%
SCE	64%	
PG&E	63%	

Wind/Solar Dispatch Assumptions in Solar Area

	Solar	Wind
SDG&E	79%	44%
SCE	77%	
PG&E	79%	

Offshore Wind	100%
OOS Wind	67%

Agenda

- Policy-driven assessment objectives and scope
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Next steps

- Preliminary results of the policy-driven assessment will be presented at the November 17 stakeholder meeting

Economic Assessment
Unified Planning Assumptions & Study Plan

Yi Zhang

2022-2023 Transmission Planning Process Stakeholder Meeting
February 28, 2021

Economic planning study

- The CAISO economic planning study follows the CAISO tariff and Transmission Economic Assessment Methodology (TEAM) to do the following studies
  - Congestion analysis
  - Study request evaluations
  - Economic assessments

Production cost model (PCM)

- 2032 ADS PCM will be used as a starting point
  - The first release is projected to be available by June 30, 2022
  - Expected to have multiple incremental releases in the second half of the year
- The unified planning assumptions will be used to update the CAISO system model in the PCM
- Other model updates would be also needed through the PCM development and validation process
  - Will be discussed in future stakeholder meetings

Production cost simulation and congestion analysis

- Production cost simulations will be conducted using Hitachi Energy GridView software on the CAISO's planning PCM

- Congestion analysis and renewable curtailment analysis
  – The analysis results will be considered in finalizing the selection of high priority areas for economic assessment, and in the policy study as well

Economic planning study requests

- Economic Planning Study Requests are to be submitted to the CAISO during the comment period of the draft Study Plan

- The CAISO will evaluate and consider the Economic Planning Study Requests as set out in section 24.3.4.1 of the CAISO Tariff

Selection of high priority areas for detailed study

- In the Study Plan phase of a planning cycle, the CAISO has carried all study requests forward as potential high priority study requests, which are mainly based on the previous cycle's congestion analysis
- The congestion and curtailment results in the current cycle will be considered in finalizing the high priority areas, since changing circumstances may lead to more favorable results
- This approach gives more opportunity for the study requests to be considered, and can take into account the latest and most relevant information available

Economic assessment

- Economic benefit assessment is based on TEAM
  - Production cost benefit
  - Other benefits, such as capacity benefit, are assessed on a case by case basis
- Cost estimates are based on either per unit cost or study request submittal if available
- Total benefit and total cost (revenue requirement) are used in benefit-to-cost ratio calculation

California ISO

Frequency Response Assessment
Unified Planning Assumptions & Study Plan

Christopher Fuchs

2022-2023 Transmission Planning Process Stakeholder Meeting

February 28, 2022

Background and Objective

- Majority of the existing Invert Based Resources (IBR) do not provide frequency response but FERC Order 842 now requires that all IBRs that sign LGIAs to have frequency response capability.
- The ability of IBR with frequency control enabled to response to system events with enough available operating headroom is now well-established from prior planning studies.
- The objective of this study is to assess the CAISO system frequency response in years 2027 and 2032 and identify any potential planning scenario gaps during which contingencies can restrict primary frequency response or during which the system is vulnerable to frequency events.

Study Models and Assumptions

- Overall study approach is similar to frequency response assessment performed in prior TPP cycles. However in this cycle:
  - The frequency response of the system both in year 2027 and year 2032 will be studied.
  - A review of the frequency response of individual units across the CAISO system will be performed for a number of NERC frequency events.
  - Frequency response from CAISO IBR plants (solar, wind, and storage) in the studies will checked against reference and expected behavior.

Contingency and Monitored Parameters

- The trip of two fully dispatched Palo Verde units will be simulated and the following parameters under each scenario will be monitored:
  - System frequency including frequency nadir and settling frequency after primary frequency response.
  - The total change in IBR output from pre- to post-contingency.
  - The major path flows.
  - Frequency response of the WECC and CAISO (MW/0.1 Hz).
  - Rate of Change of Frequency (ROCOF).
  - State of Charge of BESS installations.

Study Scenarios

- Scenario 1: Frequency response from all new and existing IBRs in CAISO system will have frequency control switched off to establish a baseline.
- Scenario 2: Maximize use of solar plant headroom when Battery Energy Storage Systems (BESS) are at the start of their charging cycle. Input with regards to actual operation will be obtained to best simulate BESS behavior under low state of charge during a system event.
- Scenario 3: maximize existing and new BESS with capable control so that they run with an adequate amount of headroom output during end-of-day peak load conditions with a pre-existing single element outage. The pre-contingency equipment outage has yet to be determined but will be representative of system operating experience and maintenance. The level of headroom will be determined as per the new base cases and BESS availability.

Study Scenarios (cont'd)

- Scenario 4: Starting with Scenario 2 it will be assumed that the generator headroom in CAISO areas will be set at spinning reserve.
- Scenario 5: Starting with Scenario 3 it will be assumed that the generator headroom in CAISO areas will be set at spinning reserve.

California ISO

Next Steps
Unified Planning Assumptions & Study Plan

Elizandra Casillas
Stakeholder Engagement and Policy Specialist

2022-2023 Transmission Planning Process Stakeholder Meeting
February 28, 2022

2022-2023 Transmission Planning Process Next Steps

- Stakeholders requested to submit comments to: regionaltransmission@caiso.com
  - Economic study requests and
  - Maximum Import Capability (MIC) expansion requests are to be submitted with comments
- Stakeholder comments are to be submitted within two weeks after stakeholder meetings: **by March 14**
- CAISO will post comments and responses on website
- Final Study Plan will be posted on March 31