Agenda

Unified Planning Assumptions & Study Plan

Isabella Nicosia

Associate Stakeholder Engagement and Policy Specialist

2020-2021 Transmission Planning Process Stakeholder Meeting

February 28, 2020

2020-2021 Transmission Planning Process Stakeholder Meeting - Agenda

Topic	Presenter
Introduction	Isabella Nicosia
Overview & Key Issues	Jeff Billinton
Reliability Assessment	Nebiyu Yimer
Policy Assessment	Sushant Barave
Economic Assessment	Yi Zhang
Wrap-up & Next Steps	Isabella Nicosia

Overview
Unified Planning Assumptions & Study Plan

Jeff Billinton
Director, Transmission Infrastructure Planning

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2020

2020-2021 Transmission Planning Process

December 2019

April 2020

March 2021

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

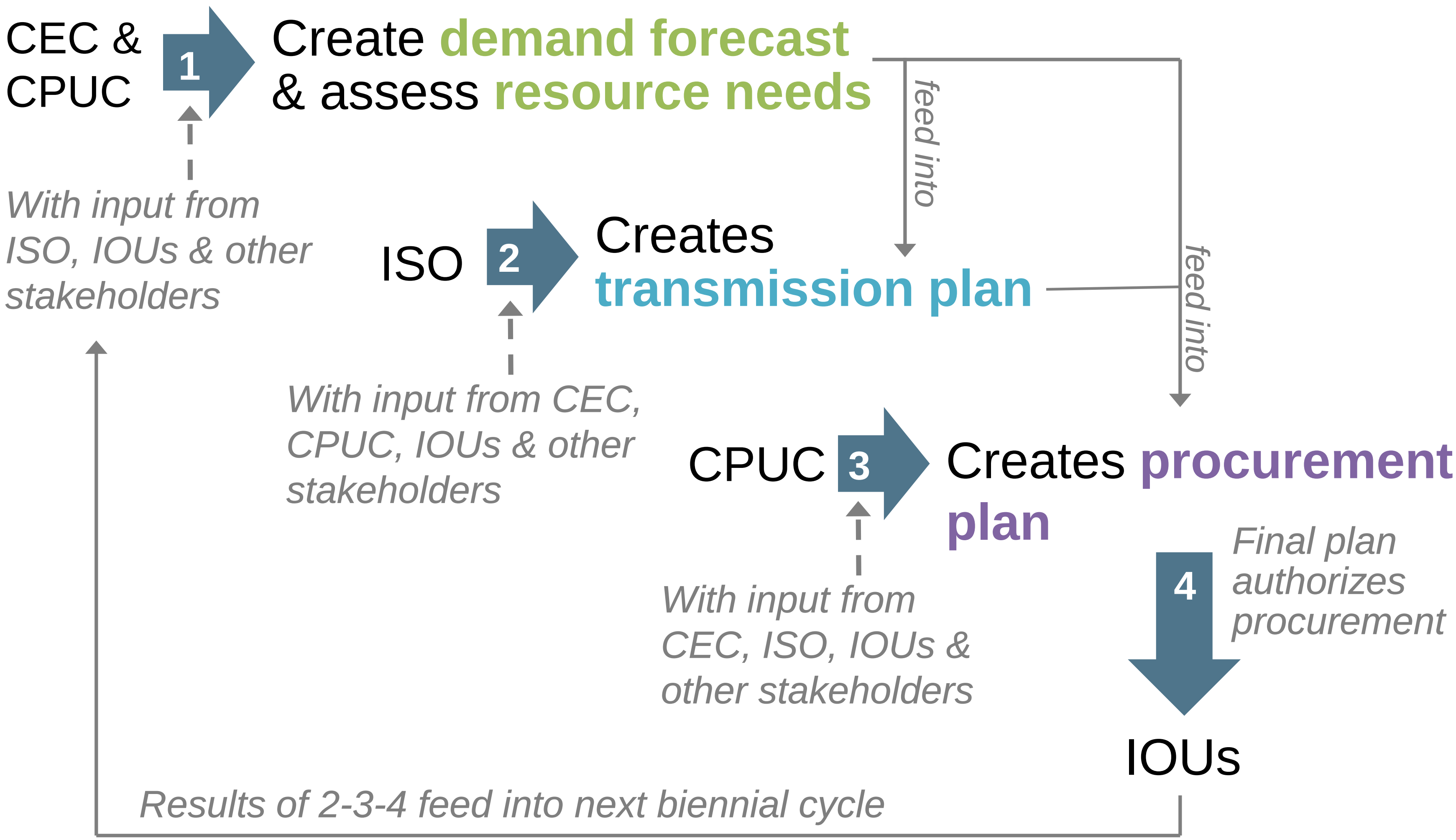
CAISO Board for approval of transmission plan

California ISO

2020-2021 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 13
- Final Study Plan to be posted on March 31
- Preliminary reliability study results to be posted on August 14
- Stakeholder meeting on September 23 and 24
- Comments to be submitted by October 7
- Request window closes October 15
- Preliminary policy and economic study results on November 17
- Comments to be submitted by December 1
- Draft transmission plan to be posted on January 31, 2019
- Stakeholder meeting in February
- Comments to be submitted within two weeks after stakeholder meeting
- Revised draft for approval at March Board of Governor meeting

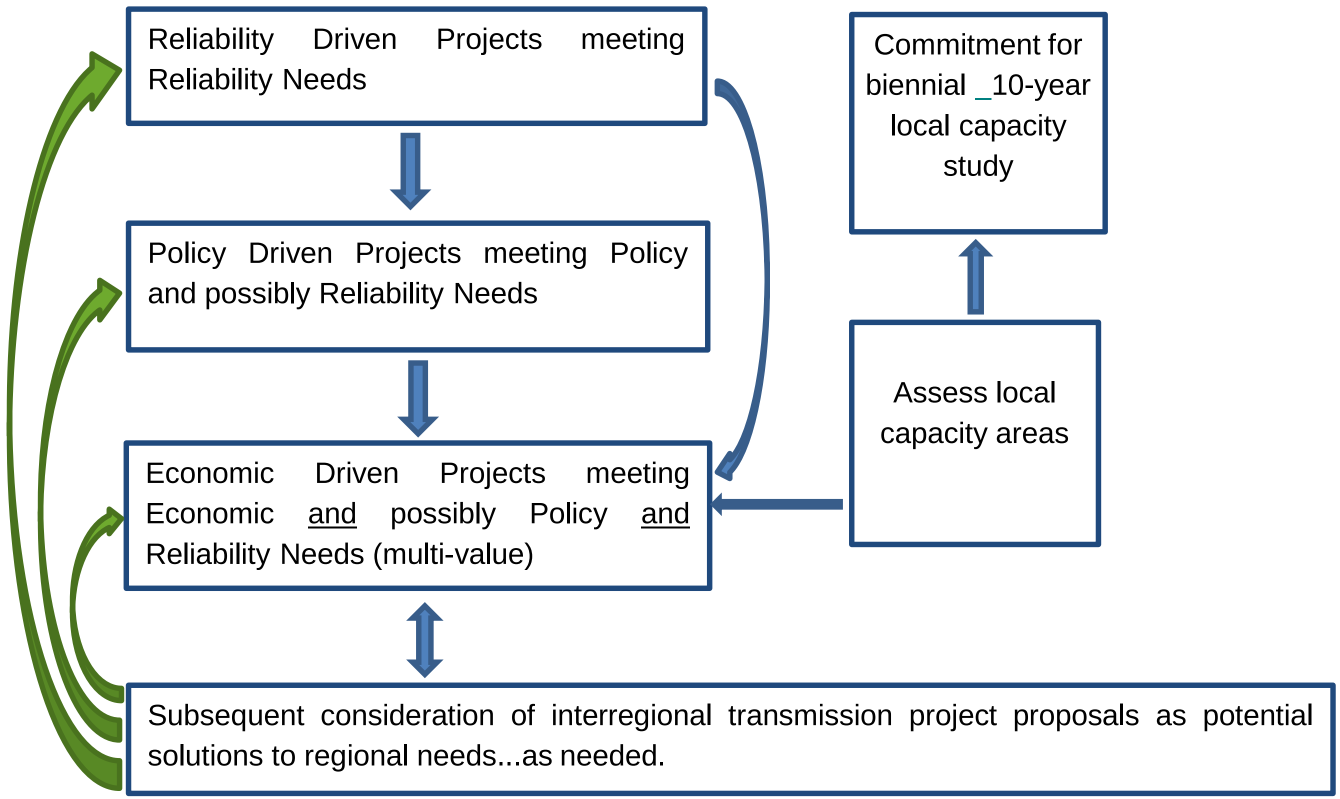
Planning and procurement overview



Key Issues in 2020-2021 Transmission Plan Cycle:

- CAISO will incorporate renewable portfolios from the CPUC
  - Baseline portfolio
    - Reliability, Policy and Economic Assessments
  - Sensitivity portfolios
    - Policy Assessment

Studies are coordinated as a part of the transmission planning process



2020-2021 Transmission Plan Study Plan

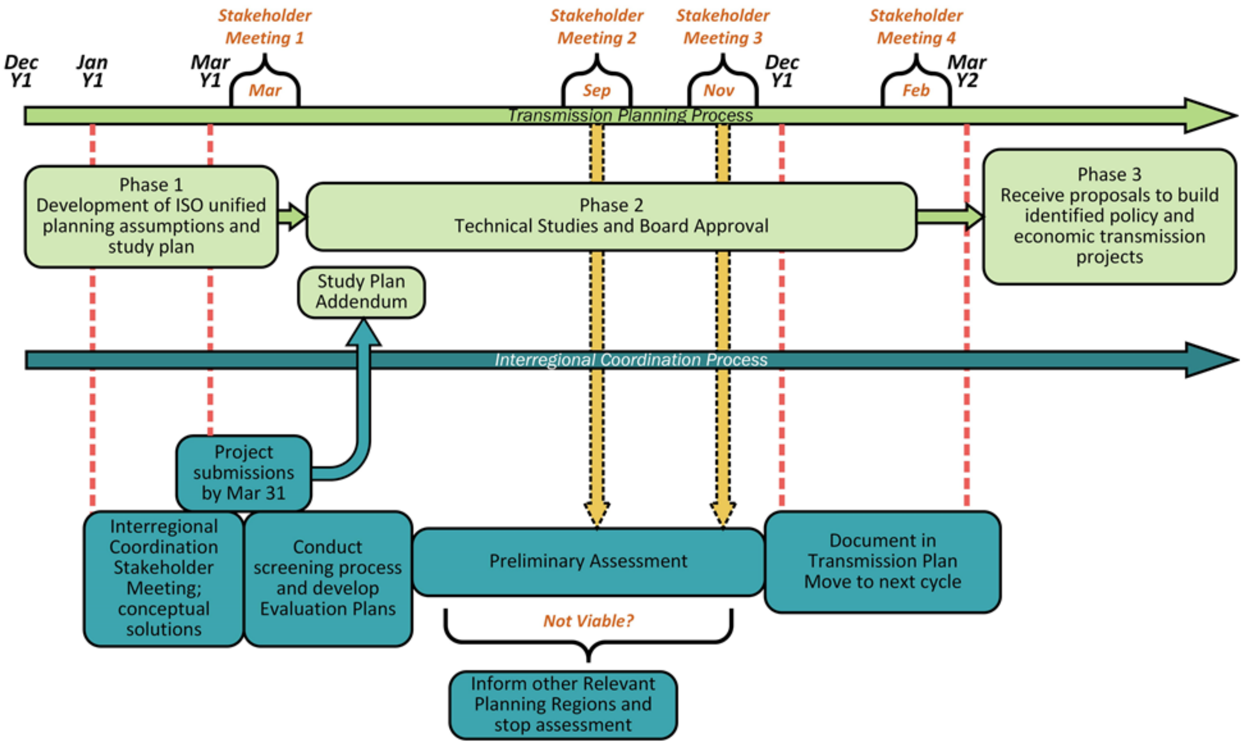
- Reliability Assessment to identify reliability-driven needs
- Policy Assessment to identify policy-driven needs
- Economic Planning Study to identify needed economically-driven elements
- Interregional Transmission Planning Process
  - In year one (even year) of 2 year planning cycle
- Other Studies
  - Local Capacity Requirements
    - Near-Term (2021) and Mid-Term (2025)
    - Long-term (2030)
      - Considering additional information related to storage potential
  - Long-term Congestion Revenue Rights
  - Frequency response
  - Flexible deliverable capacity
    - Considering biennial assessment

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 2020-2021 TPP planning cycle

- Interregional Coordination stakeholder meeting held on February 27

Year 1 (Even Year) - Interregional Coordination Process



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

Study Information

- Final Study Plan will be posted on 2020-2021 transmission planning process webpage on March 31st
  http://www.caiso.com/planning/Pages/TransmissionPlanning/2020-2021TransmissionPlanningProcess.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

Stakeholder comments

- Stakeholders requested to submit comments to: regionaltransmission@caiso.com
- Stakeholder comments are to be submitted within two weeks after stakeholder meetings: **by March 13**
- CAISO will post comments and responses on website

Reliability Assessment
Unified Planning Assumptions & Study Plan

Binaya Shrestha / Nebiyu Yimer
Regional Transmission Engineer Lead

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2020

Planning Assumptions

- Reliability Standards and Criteria
  - California ISO Planning Standards
  - NERC Reliability Criteria
    - TPL-001-5
    - NUC-001-3
  - WECC Regional Criteria
    - TPL-001-WECC-CRT-3.2

Planning Assumptions

- Major changes in TPL-001-5
  - Protection system “single point of failure” refers to a non-redundant component of a protection system.
  - Removal of exclusion of known outages of less than six months.
  - Requirements for stability analysis to assess the impact of the possible unavailability of long lead time equipment.

Planning Assumptions
(continued)

- Study Horizon
  - 10 years planning horizon
    - near-term: 2021 to 2025
    - longer-term: 2026 to 2030

- Study Years
    - near-term: 2022 and 2025
    - longer-term: 2030

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

- Starting this cycle, the CAISO will evaluate areas known to have no major changes compared to assumptions made in prior planning cycles for potential use of past studies.
- Within the current TPL-001-5 Standard, the Requirement R2.6 allows for use of past studies to support the planning assessment.
- At a high level, the process will include three major steps. 1) Data collection, 2) Evaluation of data change and 3) Drawing conclusions using outcome of data change evaluation and engineering judgement.
- 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
  - The study models the existing and new reactive power resources in the base cases to ensure that realistic reactive support capability will be included in the study
- Protection Systems
  - The major new and existing SPS, safety nets, and UVLS that will be included in the study
  - Continue to include RAS models and work with PTOs to obtain remaining RAS models.
- Control Devices
  - Several control devices were modeled in the studies

Load Forecast Assumptions
Energy and Demand Forecast

- California Energy Demand Updated Forecast 2020-2030 adopted by California Energy Commission (CEC) on January 22, 2020 will be used:
  - Using the Mid Baseline LSE and Balancing Authority Forecast spreadsheets
  - Additional Achievable Energy Efficiency (AAEE)
    - Consistent with CEC 2019 IEPR
    - Mid AAEE will be used for system-wide studies
    - Low AAEE will be used for local studies
  - CEC forecast information is available on the CEC website at:
    http://www.energy.ca.gov/2019_energypolicy/documents/

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 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 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 2020-2021 TPP base cases.
  - Amount of the BTM-PV to be modeled will be based on 2019 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 2020-2021 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.
- AAEE will be modeled using the CEC provided bus-bar allocations and will be modeled as negative load.

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

- CPUC Proposed Decision: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M327/K750/327750339.PDF
  - Base portfolio (for Reliability, Policy and Economic Assessment)

- **Base portfolio** modeling assumptions to be used in 2020-2021 TPP:
  - CPUC Staff Report: Modeling Assumptions for the 2020-2021 TPP (Release 1 covering base portfolio details) ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2020_2021_TPP-Report-Release1.pdf

Generation Assumptions

- One-year operating cases
- 2-5-year planning cases
  - Generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study;
  - Conventional generation in pre-construction phase with executed LGIA and progressing forward will be modeled off-line but will be available as a non-wire mitigation option.
  - OTC repowering projects will be modeled in lieu of existing resources as long as they have power purchase approval from the CPUC or other Local Regulatory Agency (LRA) and are projected to be in service within the timeframe of the study.
  - The contracted resources considered to be baseline assumptions for selecting the CPUC's Base Portfolio will be utilized for modeling specific generation.
- 6-10-year planning cases
  - The CPUC's Portfolio
- Retired generation is modeled offline and disconnected in appropriate study years
- Generation greater than 40 years old modeled offline; however may be dispatched for identified reliability needs

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, aggregate <10 MW same technology

Generation Assumptions
Generation Retirements

- Nuclear Retirements
  - Diablo Canyon will be modeled off-line based on the OTC compliance date
- Once Through Cooled Retirements
  - Separate slide below for OTC assumptions
- Renewable and Hydro Retirements
  - Assumes these resource types stay online unless there is an announced retirement date.
- Other Retirements
  - Unless otherwise noted, assumes retirement based resource age of 40 years or more. List included in Appendix A of the draft study plan.

Generation Assumptions
OTC Generation

Modeling of the once-through cooled (OTC) generating units follows the State Water Resources Control Board (SWRCB)'s Policy on OTC plants with the following exception:

- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table A2-1 in the draft study plan; and
- All other OTC generating units will be modeled off-line beyond their compliance dates, as illustrated in Table A2-1, or per proposed retirements by the generation owners to proceed on repowering projects that have been approved by the state regulatory agencies.

Generation Assumptions

CEC permitted resources or CPUC-approved long-term procurement resources (Thermal and Solar Thermal)

PTO Area	Project	Capacity (MW)	Expected In-service Date
SCE	Huntington Beach Energy Project Unit 6 (CCGT) *	644	2020
	Alamitos Energy Center Unit 8 (CCGT) *	640	2020

Notes:

*These projects have received PPTA approvals from the CPUC as part of Long Term Procurement Plan (LTPP) process.

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
  - CPUC Decision (D.)13-10-040 established a 2020 procurement target of 1,325 MW installed capacity of new energy storage units within the CAISO planning area.
  - Existing and proposed energy storage that will be procured by IOUs including approved by CPUC.
  - Behind-the-meter energy storage is netted to load due to tool limitation and lack of locational information.
  - The CPUC staff has indicated that while considering portfolio-selected storage as a mitigation option for reliability issues, the ISO should not include the full capital cost of storage in the assessment of alternatives.

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)	4,000	Summer Peak
PDCI (N-S)	3,220	
Path 66 (N-S)	4,800	
Path 15 (N-S)	-5,400	Spring Off Peak
Path 26 (N-S_	-3,000	
Path 66 (N-S)	-3,675	Winter Peak

Southern area (SCE & SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Near-Term Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
Path 26 (N-S)	3,000	0 to 3,000	Spring Off Peak
PDCI (N-S)	3220	3220	Summer Peak
West of River (WOR)	11,200	5,000 to 11,200	Summer Peak
East of River (EOR)	10,100	4,000 to 10,100	Summer Peak
San Diego Import	2765~3565	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	600	0 to 408	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
	2022	2025	2030
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	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
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		
		2022	2025	2030	2022	2025	2030	2022	2025	2030	2022	2025	2030	2022	2025	2030
PG&E	Summer Peak	7/28 HE 18	See CAISO	See CAISO	17%	See CAISO	See CAISO	10%	See CAISO	See CAISO	62%	See CAISO	See CAISO	100%	See CAISO	See CAISO
PG&E	Spring Off Peak	4/2 HE 13	See CAISO	See CAISO	80%	See CAISO	See CAISO	92%	See CAISO	See CAISO	20%	See CAISO	See CAISO	27%	See CAISO	See CAISO
PG&E	Winter Off peak			11/9 HE 4			0%			0%			13%			44%
PG&E	Winter peak	12/12 HE 19	12/8 HE 19	12/9 HE 19	0%	0%	0%	0%	0%	0%	13%	13%	13%	75%	77%	79%
SCE	Summer Peak	9/6 HE 16	9/2 HE 17	9/3 HE 19	44%	23%	0%	51%	21%	0%	20%	25%	40%	100%	100%	100%
SCE	Spring Off Peak	4/3 HE 12	See CAISO	See CAISO	80%	See CAISO	See CAISO	96%	See CAISO	See CAISO	34%	See CAISO	See CAISO	31%	See CAISO	See CAISO
SDG&E	Summer Peak	9/7 HE 19	9/3 HE 19	9/4 HE 19	0%	0%	0%	0%	0%	0%	33%	33%	33%	100%	100%	100%
SDG&E	Spring Off Peak	4/9 HE 13	See CAISO		78%	See CAISO		95%	See CAISO		30%	See CAISO		23%	See CAISO	
VEA	Summer Peak	6/24 HE 16	6/27 HE 16	6/28 HE 16				36%	36%	36%				100%	100%	100%
VEA	Spring Off Peak	4/15 HE 3	4/18 HE 3		0%	0%		0%	0%					33%	33%	

PTO	Scenario	Day/Time	BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of non-coincident PTO managed peak load		
			PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	2030 Summer Peak	9/3 HE 19	0%	0%	0%	0%	0%	0%	42%	40%	33%	95%	100%	98%
CAISO	2030 Spring Off Peak	4/7 HE 13	80%	81%	80%	92%	94%	95%	20%	34%	30%	16%	23%	14%
CAISO	2025 Summer Peak	9/2 HE 18	8%	5%	4%	4%	2%	1%	32%	32%	27%	94%	99%	95%
CAISO	2025 Spring Off Peak	5/3 HE 20	0%	0%	0%	0%	0%	0%	60%	59%	68%	64%	57%	66%

Study Scenarios - *Sensitivity Studies*

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2022	2025	2030
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 and minimum gas generation commitment	-	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 high SVP forecasted load			PG&E Greater Bay Area
Summer Peak with forecasted load addition	VEA Area	VEA Area	
Summer Off peak with heavy renewable output		VEA Area	
Summer Peak with Retirement of QF Generations	-	-	PG&E Kern Area
Summer Peak without Facility Rerates			PG&E Bulk PG&E Local Areas

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 high CEC forecasted load	2025 Summer Peak	3%	3%	2%	2%	71%	71%	Load increased by turning off AAEE
PG&E	Off peak with heavy renewable output and minimum gas generation commitment	2025 Spring Off-peak	0%	99%	0%	99%	60%	64%	Solar and wind dispatch increased to average of 20% exceedance values
PG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2022 Summer Peak	17%	99%	10%	99%	62%	62%	Solar and wind dispatch increased to 20% exceedance values
PG&E	Summer Peak with Retirement of QF Generations	2030 Summer Peak	0%	0%	0%	0%	42%	42%	All QF facilities in Kern area turned off
PG&E	Summer Peak with high SVP forecasted load	2030 Summer Peak	0%	0%	0%	0%	42%	42%	Use SPV's forecast for 2030
PG&E	Summer Peak without Facility Rerates	2030 Summer Peak	0%	0%	0%	0%	42%	42%	Study to be performed using regular (non-rerated) facility ratings
SCE	Summer Peak with high CEC forecasted load	2025 Summer Peak	23%	23%	21%	21%	25%	25%	Load increased per CEC high load scenario
SCE	Off peak with heavy renewable output and minimum gas generation commitment	2025 Spring Off-peak	0%	91%	0%	99%	59%	67%	Solar and wind dispatch increased to 20% exceedance values
SCE	Summer Peak with heavy renewable output and minimum gas generation commitment	2022 Summer Peak	44%	91%	51%	99%	20%	0%	Solar and wind dispatch decreased with net load unchanged
SDG&E	Summer Peak with high CEC forecasted load	2025 Summer Peak	0%	0%	0%	0%	33%	33%	Load increased per CEC high load scenario
SDG&E	Off peak with heavy renewable output and minimum gas generation commitment	2025 Spring Off-peak	0%	96%	0%	96%	68%	51%	Solar and wind dispatches increased to 20% exceedance values with net load unchanged at 57% of summer peak
SDG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2022 Summer Peak	0%	96%	0%	96%	33%	51%	Solar and wind dispatches increased to 20% exceedance values
VEA	Summer Peak with forecasted load addition	2022 Summer Peak	44%	44%	36%	36%	-	-	Load increase reflect future load service request
VEA	Summer Peak with forecasted load addition	2025 Summer Peak	44%	44%	36%	36%	-	-	Load increase reflect future load service request
VEA	Off-peak with heavy renewable output	2025 Spring Off-peak	0%		0%		-	-	Modeled active GIDAP projects in the queue

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
2022	Summer Peak	20HS3a1	2019
	Winter Peak	20HW3a1	2019
	Spring Off-Peak	20LSP1sa1	2019
2025	Summer Peak	25HS2a1	2019
	Winter Peak	25HW2a1	2019
	Spring Off-Peak	20LSP1sa1	2019
2030	Summer Peak	30HS1a1	2019
	Winter Peak	30HW1a1	2019
	Spring Off-Peak	30LSP1Sa1	2019
	Winter Off-Peak	30LSP1Sa1	2019

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-001-4)**
  - As a part of the planning assessment the ISO assesses Extreme Event contingencies per the requirements of TPL-001-4;
    - however the analysis of Extreme Events will not be included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

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

- The technical studies mentioned in this section will be used for identifying mitigation plans for addressing reliability concerns.
- As per ISO tariff, identify the need for any transmission additions or upgrades required to ensure System reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards.
  - In making this determination, the ISO, in coordination with each Participating TO with a PTO Service Territory 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

Sushant Barave
Senior Advisor, Regional Transmission South

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2019

Agenda

- Policy-driven assessment objectives and methodology
- Description of portfolios transmitted (and to be transmitted) by the CPUC
- Modeling data transmitted by the CPUC for 2020-2021 TPP

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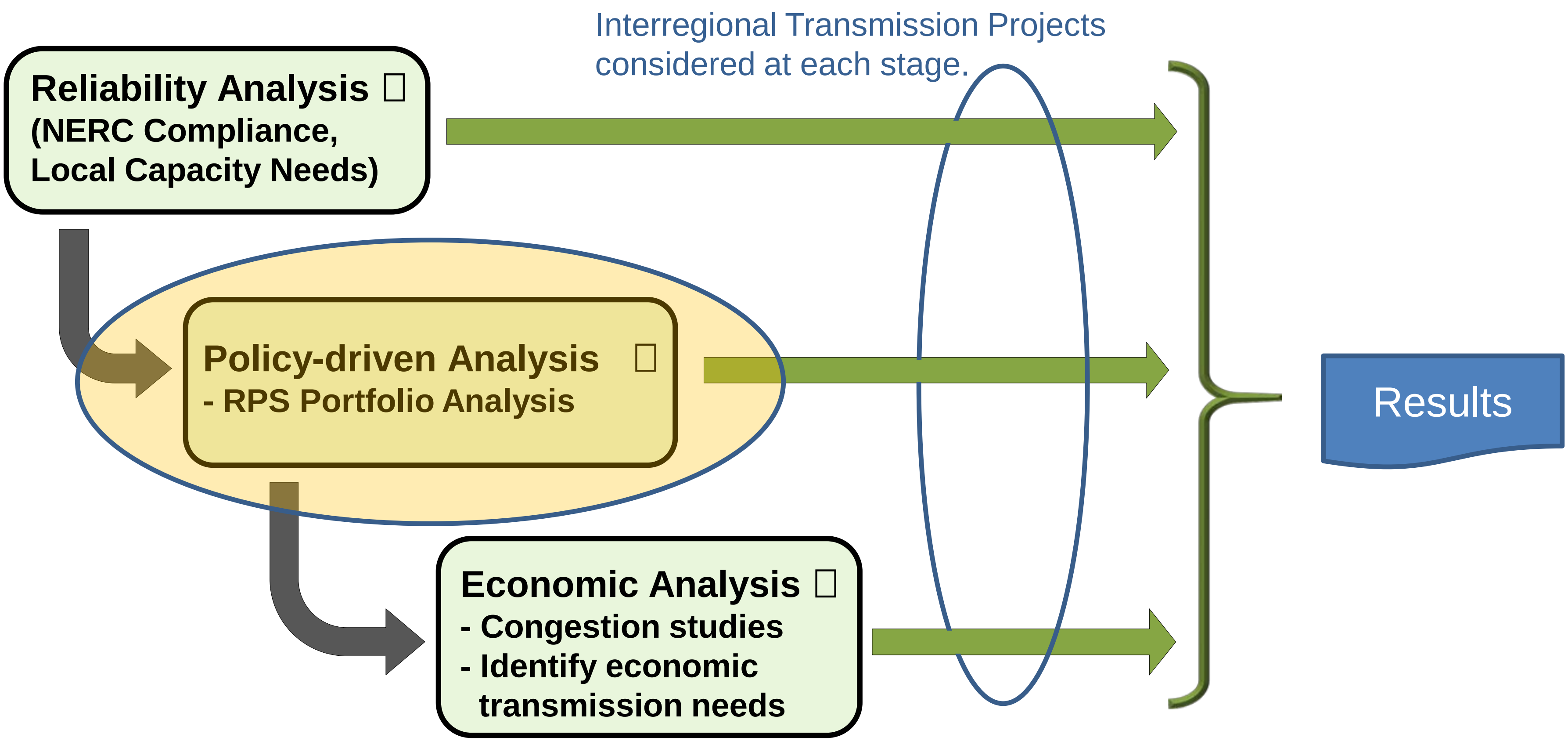
Evaluation of transmission solutions needed to meet state, municipal, county or federal policy requirements:



Key objectives of the policy-driven assessment in 2020-2021 TPP:

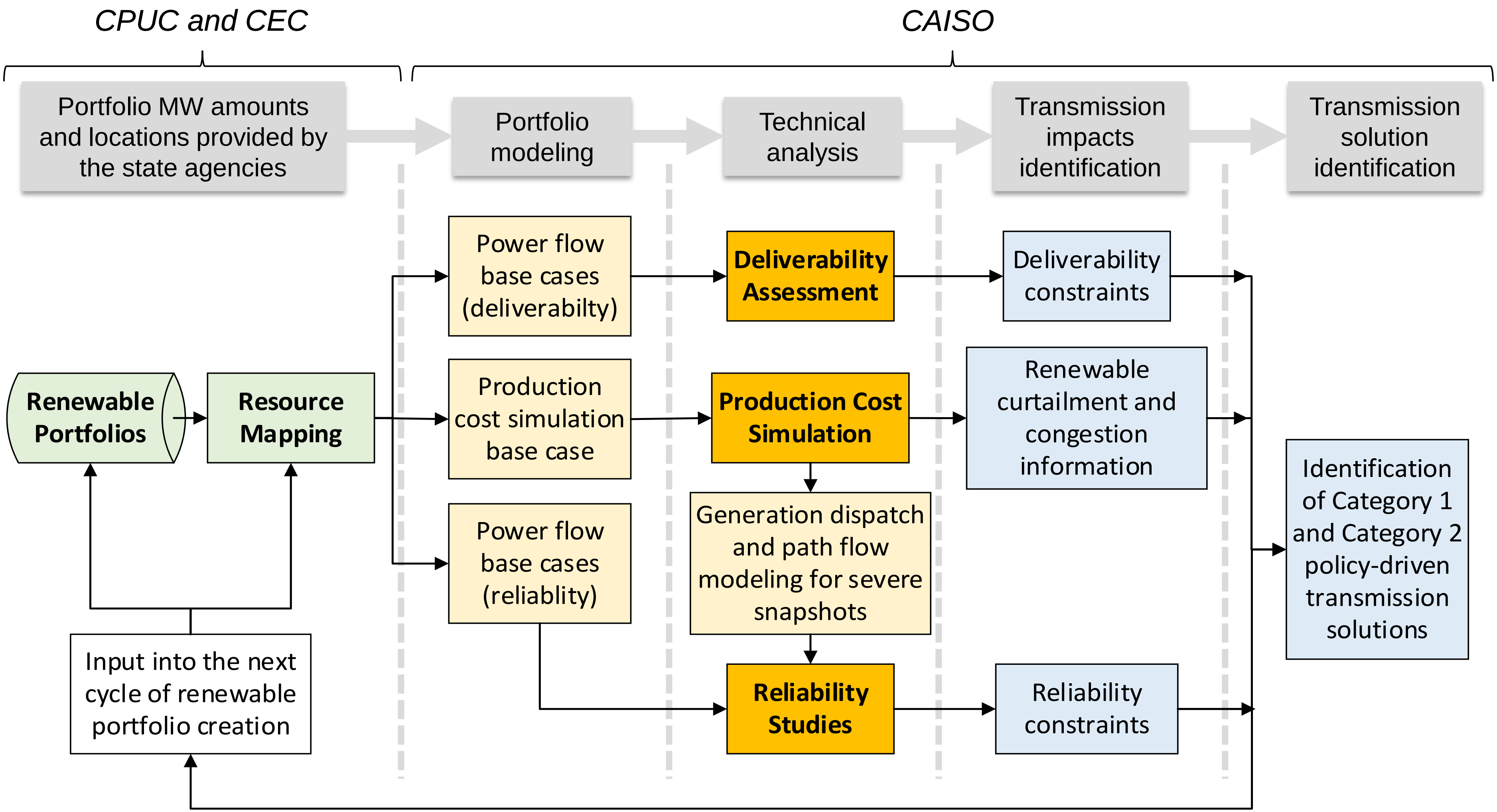
1. Study the transmission impacts of the base and sensitivity portfolios transmitted to the CAISO by CPUC
   a. Capture powerflow and stability impacts
   b. Test the deliverability of resources selected to be full capacity deliverability status (FCDS)
   c. Analyze renewable curtailment data

2. Evaluate transmission solutions (Category 1 and Category 2) needed to meet state, municipal, county or federal policy requirements or directives

3. Test the CAISO-provided transmission capability estimates used in CPUC's integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation

4. Support and test the framework based on CPUC-provided objectives for siting generic storage selected in CPUC IRP process

The policy assessment framework relies on three study components to identify transmission impacts and solutions



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The CPUC Proposed Decision released on February 21, 2020 recommended portfolios for use in TPP

- Proposed Decision: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M327/K750/327750339.PDF
  - Base portfolio (for Reliability, Policy and Economic Assessment)
  - Sensitivity portfolio #1 (for Policy Assessment)
  - Sensitivity portfolio #2 (for Policy Assessment)
- The CPUC staff developed the base and sensitivity portfolios using RESOLVE capacity expansion model

Policy-driven **base portfolio**:
Adjusted Preferred System Plan (2017-2018 IRP)

- The base portfolio for reliability, policy and economic assessment is based on the 2018 Preferred System Portfolio (PSP) adopted in D.19-04-040, with certain updates.

- GHG target for the electric sector used in this portfolio is 46 million metric tons (MMT) by 2030.

Policy-driven **sensitivity portfolio #1**: Reference System Portfolio (2019-2020 IRP)

- GHG target for the electric sector used in this portfolio is 46 million metric tons (MMT) by 2030.

- This portfolio significantly varies from the previous portfolios analyzed for TPP purposes and warrants analysis as a sensitivity prior to moving to investment stage.

- Consists of new buildout of ~11,000 MW in-state solar, ~2,800 MW in-state wind, ~600 MW out-of-state wind and ~9,800 MW energy storage.

Policy-driven **sensitivity portfolio #2**: High energy-only buildout (2019-2020 IRP)

- A portfolio to test areas in which the benefits of inexpensive transmission solutions could help reduce curtailment of renewables.

- Relaxed the energy-only transmission capability estimates in zones that are expected to offer relatively low-cost upgrade options to mitigate renewable curtailment.

- GHG target for the electric sector used in this portfolio is 30 million metric tons (MMT) by 2030.

Agenda

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Base portfolio modeling assumptions to be used in 2020-2021 TPP

- CPUC Staff Report: Modeling Assumptions for the 2020-2021 TPP (Release 1 covering base portfolio details) ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2020_2021_TPP-Report-Release1.pdf

- CEC's busbar mapping results (base portfolio) https://caenergy.databasin.org/galleries/eab0ce3a5be447ce928a310e80c65c8d#expand=208848

Sensitivity portfolios modeling assumptions to be used in 2020-2021 TPP

- CPUC Staff Report: Modeling Assumptions for the 2020-2021 TPP
(Release 2 expected in March 2020)

- CEC's busbar mapping results
(expected in March 2020)

Resource mix selected in the base portfolio

RESOLVE Resource	Additions to 2019 Baseline since 2018 PSP MW	2030 Selected Resources, 2018 PSP as at March 2019 MW	2030 Selected Resources, post Baseline Rec at February 2020 MW	FOR MAPPING Post NoCal Geothermal substitution MW
Greater_Imperial_Geothermal	20	1,276	1,256	**1,256**
Northern_California_Geothermal		424	424	**-**
Carrizo_Wind		160	160	**160**
Central_Valley_North_Los_Banos_Solar	22	-	-	**-**
Central_Valley_North_Los_Banos_Wind		146	146	**146**
Greater_Imperial_Solar	471	-	-	-
Inyokern_North_Kramer_Solar	23	577	554	**554**
Kern_Greater_Carrizo_Solar	5	-	-	-
North_Victor_Solar	14	-	-	-
Riverside_Palm_Springs_Solar	126	1,320	1,194	***1,622***
Riverside_Palm_Springs_Wind		42	42	***42***
Solano_Wind		643	643	**643**
Southern_Nevada_Solar		2,304	2,304	**2,304**
GLW-VEA_Solar		702	702	**702**
Tehachapi_Solar	288	1,013	725	***1,153***
Tehachapi_Wind	169	153	-	-
Westlands_Solar	290	-	-	-
Arizona_Solar		-	-	***428***
Total	**1,427**	**8,760**	**8,150**	**9,011**

Source: ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2020_2021_TPP-Report-Release1.pdf

In addition to these resources, 1,157 MW of 1.3-hour storage and up to 1,000 MW of 4-hour storage in included in the base portfolio.

Generic energy storage mapping and modeling - base portfolio

- CPUC staff has not mapped the generic storage resources to specific locations.
- The CAISO will consider these generic storage resources as potential mitigation options for reliability needs identified in TPP.
- The CPUC staff has indicated that while considering portfolio-selected storage as a mitigation option for reliability issues, the CAISO should not include the full capital cost of storage in the assessment of alternatives.

Generic energy storage mapping and modeling - sensitivity portfolio #1 and #2

- CPUC staff is in the process of mapping generic storage to specific locations for the sensitivity portfolios.

- The approach and the findings are expected to be included in “Modeling Assumptions for the 2020-2021 TPP (Release 2)”

Economic Assessment
Unified Planning Assumptions & Study Plan

Yi Zhang

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2020

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)

- 2030 ADS PCM will be used as a starting point
  - The first release of the 2030 ADS PCM is projected to be available at the end of June, 2020
- The unified planning assumptions will be used to update the CAISO system model in the PCM, consistent with the CAISO's TPP reliability study
  - Transmission topology
  - Generator assumptions for existing generators, renewable portfolio (CPUC Base Portfolio), energy storage, and retirement
  - Load forecast for 2030 will use the same CEC forecast, but use1-in-2 peak demand to adjust load profiles
- 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 ABB GridView software on the CAISO's planning PCM
- Congestion analysis and renewable curtailment analysis will use the production cost simulation results
  - The analysis results will be considered in finalizing the selection of high priority areas, 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

California ISO

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 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

- The CAISO will conduct economic assessments for the selected high priority areas
- Economic benefit assessment is based on TEAM
  - Production cost benefit is assessed using production cost simulation results
  - 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

Next Steps
Unified Planning Assumptions & Study Plan

Isabella Nicosia
Associate Stakeholder Engagement and Policy Specialist

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2020

2020-2021 Transmission Planning Process Next Steps

- Stakeholders requested to submit comments to: regionaltransmission@caiso.com
- Stakeholder comments are to be submitted within two weeks after stakeholder meetings: **by March 13**
- CAISO will post comments and responses on website
- Final Study Plan will be posted on March 31