Agenda
Preliminary Policy and Economic Assessment Results

Kim Perez
Stakeholder Engagement and Policy Specialist

2016-2017 Transmission Planning Process Stakeholder Meeting
November 16, 2016

2016-2017 Transmission Planning Process Stakeholder Meeting - Agenda – Day 1

Topic	Presenter
Introduction	Kim Perez
Overview	Neil Millar
TEAM Methodology Overview and Update	Yi Zhang
Preliminary Policy Results	Luba Kravchuk
Preliminary Economic Results	Yi Zhang
50% RPS Special Study Update	Sushant Barave
Gas / Electric Coordination	David Le Binaya Shrestha
North Area - Review of Previously Approved Projects	Jeff Billinton
Wrap-up & Next Steps	Kim Perez

Introduction and Overview
Policy-Driven and Economic Assessment

Neil Millar
Executive Director, Infrastructure Development

2016-2017 Transmission Planning Process Stakeholder Meeting
November 15, 2015

2016-2017 Transmission Planning Process

January 2016 | April 2016 | March 2017

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

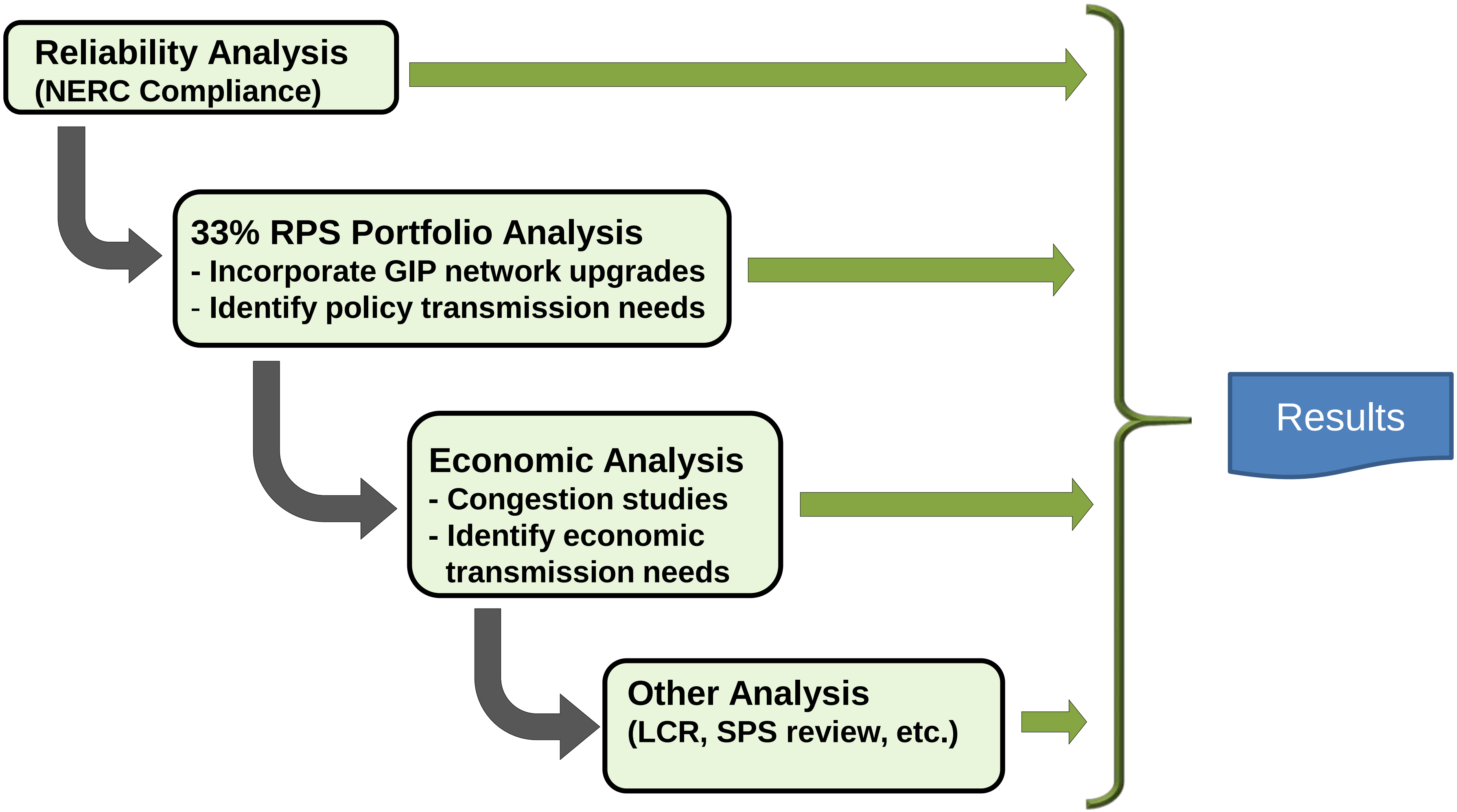
Publish comprehensive transmission plan with recommended projects

Phase 3 Procurement

And update on ongoing reliability analysis issues and special studies

ISO Board for approval of transmission plan

Development of 2016-2017 Annual Transmission Plan



2016-2017 Ten Year Plan Milestones

- Preliminary reliability study results were posted on August 15
- Stakeholder session September 21st and 22nd
- Comments received October 6
  - (slow response resource special study extended to October 10)
- Request window closed October 15
- **Today's session - preliminary policy and economic study results and update on other issues**
- Comments due by November 30
- Draft plan to be posted January, 2017

Renewable Portfolio Standard Policy Assumptions

- Portfolio direction received from the CPUC and CEC on June 13, 2016:

  “Recommend reusing the "33% 2025 Mid AAEE" RPS trajectory portfolio that was used in the 2015-16 TPP studies, as the base case renewable resource portfolio in the 2016-17 TPP studies”

  “Given the range of potential implementation paths for a 50 percent RPS, it is undesirable to use a renewable portfolio in the TPP base case that might trigger new transmission investment, until more information is available.”

- Portfolios to be used in the ISO’s informational 50% RPS special studies were provided by CPUC staff.

Update on management approval process for projects less than $50 million:

- Each year, <u>only</u> those projects less than $50 million are considered for management approval that:
  - Can reasonably be addressed on a standalone basis
  - Are not impacted by policy or economic issues that are still being assessed.
  - Are not impacted by the approval of the transmission plan (and reliability projects over $50 million) by the Board of Governors in March, 2015
- When such projects are identified (in November), approving these projects allows streamlining the review and approval process of the annual transmission plan in March of the next year
- Management only approves those projects <u>after</u> the December Board of Governors meeting
- <u>No</u> reliability transmission projects less than $50 million have been identified for management approval ahead of the March Board of Governors meeting
- Other projects less than $50 million will be identified in January and dealt with in the approval of the comprehensive plan in March.

Other study efforts in progress:

- Six special studies are being conducted in this cycle:
  - Continuation of frequency response efforts through improved modeling *(in progress)*
  - Large scale storage benefits *(in progress)*
  - Slow response resources in local capacity areas *(feedback received, parallel track anticipated, technical results will continue to be reported in transmission plan process as well)*
  - Risks of early economic retirement of gas fleet *(in progress)*
  - Gas/electric reliability coordination *
  - 50% Renewable Generation and Interregional Coordination *
- Continued review of previously-approved projects in PG&E territory *

** Updates to be presented today*

The special study plans are very ambitious:

- Draft results will be shared in the February stakeholder session but may not be in the January draft plan for all special studies
- Detailed results will be provided in the final draft plan presented to the ISO Board of Governors in March.

Economic Planning- TEAM Overview and Review of Updated Documentation

Yi Zhang
Regional Transmission Engineer Lead

2016-2017 Transmission Planning Process Stakeholder Meeting
November 16, 2016

Introduction

- Overview of TEAM
  - Transmission Economic Assessment Methodology (TEAM) was approved by 2005
  - Implementations of TEAM principles have changed as the environment changes
    - Power market evolution and renewable integration
    - ISO's practices of using TEAM in planning studies
    - Study tools advanced
  - The overview focuses on principles of TEAM and ISO's practices
- Review and update of TEAM documentation based on ISO's evolved practice
  - A documentation update – not a methodology review
  - Remove obsolete contents, and clarify and update components to reflect practices

TEAM overview

- TEAM proposed principles for economic planning and outlined a framework to implement these principles
  - Benefit assessment
  - Network representation
  - Market prices
  - Uncertainty
  - Resource alternatives
- TEAM original documentation focused on energy benefit assessment based on production cost simulation
  - Additional benefits were discussed, but lacked details of implementation due to data and modeling limitations at the time when TEAM was introduced

TEAM overview – Benefit assessment

- TEAM provides a standard for measuring transmission expansion benefits for consumers, producers, and transmission owners
- While the original methodology explored a range of perspectives, the "ratepayer" perspective has been relied upon consistently since the methodology was introduced
- Other options that had been considered initially and subsequently discarded were society and participant perspectives

TEAM overview – Economic criteria for benefit assessment

- Calculate the net present value (NPV) of the benefit of transmission expansion
  - Social discount rate is used
- “Total cost” of a transmission expansion is the present value of the annual revenue requirement
- Benefit to cost ratio (BCR) should be greater than 1.0

TEAM overview – Network model and market price

- Full network model has become the default as the production cost simulation tools advanced
  - Losses are calculated in production cost simulation
  - Transmission constraints and outages can be modeled
- Cost-based production cost simulation is used in economic planning study
  - Market power mitigations in ISO's market are more effective today than in 2005
  - Strategic bidding is not used in the ISO's current economic planning studies

TEAM overview – dealing with uncertainty

- Decisions on whether to build new transmission are complicated by risks and uncertainties about the future
- Sensitivity studies are needed to test the robustness of the economic assessment results
  - In the ISO's current practice, sensitivity cases by varying the most critical assumptions for the project under evaluation

Sensitivity analyses	Note and typical variation
Load - High	+6% above forecast
Load - Low	-6% below forecast
Hydro - High	if data available
Hydro - Low	if data available
Natural gas prices - High	+50%
Natural gas prices - Low	-25%
CA RPS portfolios	If data available
Other sensitivities per requested	n/a

  - Stochastic models can be used

TEAM overview – Resource alternatives

- Resource alternatives to transmission expansion is another principle that has been proposed in TEAM
- In current CAISO's transmission planning process, resource plans are used as input, e.g.
  - Renewable portfolios
  - DG/EE/DR
  - Energy storage
  - OTC retirement and replacement

TEAM Overview - Summary

- TEAM provided principles and a framework for economic planning studies
- Implementations of TEAM principles have changed as the environment changes
  - ISO “ratepayer’s” perspective is the only one applied
  - Full network model is default
  - Cost-based production cost simulation
  - Typical sensitivity cases are used for uncertainty
  - Resource alternatives relies on state agencies inputs
- Other updates will be discussed in the next section

REVIEW OF UPDATED TEAM DOCUMENTATION

Review of updated TEAM documentation

- Review and update TEAM documentation based on ISO's evolved practice
  - A documentation update – not a methodology review
  - Remove obsolete contents, and clarify and update components to reflect practices
- This section will cover details of:
  - Benefit assessments
  - Cost calculations
  - Market and grid modeling that impact benefit calculations

Key points in ISO’s practices of using TEAM

- Assessing economic benefits for rate-based projects
- All benefits are assessed from ISO “ratepayer’s” perspective
  - Energy benefit
  - Capacity benefit
  - Transmission loss saving benefit
  - Other benefits if applicable
- Market and grid modeling
  - EIM modeling and benefit
  - Hurdle rate
  - Ancillary services
  - Transmission constraints (such as nomograms, SPS)
  - Outages and derates that may impact routine benefits
  - Uncertainties, e.g. hydro and load assumptions

Benefit evaluation- energy benefit

- Energy benefit is assessed based on production cost simulation
  - Difference of net load payment between the cases pre and post project
- Generally,

Net load payment *= ISO's Gross load payment – ISO's Generator profit – ISO's Transmission revenue*

Gross load payment *= sum (Load x LMP)*

Generator profit *= Gen. revenue – Gen. cost*

Transmission revenue *= Congestion cost + wheeling cost*

- Ownership is used to indicate which transmission's revenue and generator's profit will be counted to offset ratepayer's payment
  - Defined as ISO "owned" in the ISO's production cost model

Benefit evaluation - ownership definition in energy benefit calculations

- ”Owned facilities” operated to the ISO ratepayer advantage include
  - PTO owned transmission
  - Generators owned by the utilities serving ISO’s load
  - Wind and Solar under contract with an ISO load serving entity to meet the state renewable energy goal
  - Other generators under contracts of which the information is available for public may be reviewed for consideration
    - Type of contract
    - Length of contract

Benefit evaluation – capacity benefit

- Local area capacity benefit
  - Potential reduction in local capacity requirement
  - Normally assessed through LCR-type studies
- System capacity benefit
  - Potential increase in import capability between regions
  - Potential capacity deficit in the importing region
  - Difference of marginal capacity costs between regions
  - Normally assessed through power flow and stability studies
- Deliverability benefit
  - Potential increase in generator deliverability to the region under study
  - Potential capacity deficit in the region under study
  - Full assessment will be on case by case basis

Benefit evaluation – transmission loss saving benefit

- Energy saving
  - Embedded in the production cost simulation results
- Peak saving
  - Can be translated to capacity benefit
  - Based on power flow study
- Generator deliverability increase
  - Can be translated to capacity benefit
  - Full assessment will be on case by case basis

Other benefits

- There are other indirect benefits that may need to be considered, but on case by case basis
- Public policy
  - A project may affect renewable portfolio calculation in accessing remote or out of state generation
  - Benefits may come from avoiding over-build
- Renewable integration
  - Reduce over-supply and curtailment
    - Transmission congestion-related
    - Market design to allow sharing energy between areas
  - A/S requirements could be reduced, depending on transmission congestion and market design for being materialized
- Avoided cost of other projects
  - If a reliability or policy project can be avoided because of the project under study

Cost calculation (revenue requirement)

- For general screening, per unit cost on the ISO website is used to estimate the capital cost, and the present value of the annual revenue requirement is estimated as 1.45 times of the capital
- If a project needs to go through the solicitation process, the cost will be the actual cost of the project as the project sponsor proposed
- For an ISO proposed project, the same model and assumptions as in the CAISO Transmission Access Charge (TAC) model are used to calculate the revenue requirement: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=7A2CFF1E-E340-4D46-8F39-33398E100AE7

Market and grid modeling – Energy Imbalance Market (EIM)

- EIM is not a day-ahead market
- EIM, however, affects the generation dispatch hence the flow pattern on the interfaces
- In the congestion studies of the ISO's previous planning cycle, EIM was considered by taking a discount on the hurdle rates among EIM entities
  - The discount was the ratio between the energy transactions through EIM and in the whole market
- It is not recommended to consider the full effect of EIM in project justification
  - Mainly due to the relative ease for entities to exit EIM and the long life of transmission assets

Market and grid modeling – Hurdle rates

- Hurdle rate is used to mimic the actual transaction hurdles between Balancing Authority Areas (BAA) or regions
- Normally, hurdle rates include
  - Transmission access charge (TAC)
  - Grid management charge (GMC)
  - Other frictions
- Hurdle rates can be modeled as
  - Exporting hurdles (in most cases), or
  - Interface hurdles
- Hurdle rates are normally implemented by adding an extra cost to generators contributing to the flow
  - Can be enforced on commitment or dispatch or both in production cost model

Market and grid modeling - others

- Ancillary services (A/S) are co-optimized with energy
  - Regulation up/down, Load following up/down, spinning/non-spinning
  - Frequency response is modeled as an A/S
- Transmission constraints in addition to facility ratings
  - Contingencies and SPS, critical and credible to local or system
    - Mostly N-1 or N-2 identified in LCR and reliability assessments
  - Nomograms, such as COI, Path 15, Path 26
  - Scheduled outages and derates
    - Only consider that may produce routine benefits

Summary of updated TEAM documentation

- The framework of TEAM remains the same
- Implementation has been updated to reflect the changes on market and grid operation, and planning processes
- ISO "ratepayer's" perspective is the perspective relied upon for benefit calculations, as the ratepayers are ultimately funding the development through rates
- Assessment of benefits in addition to energy benefit have been added to the TEAM framework
- Production cost model has been enhanced to reflect market and grid operation

Next steps

- Stakeholder comments on the updates
- Draft updated TEAM documentation

Questions/Comments?

Policy Driven Planning Deliverability Assessment

Luba Kravchuk
Senior Regional Transmission Engineer
Regional Transmission South

2016-2017 Transmission Planning Process Stakeholder Meeting
November 16, 2016

Overview of the renewable portfolio

- The 33% renewable portfolio used in the ISO’s 2016-2017 TPP studies is approximately the same as that used for the 2015-2016 TPP studies
- MW amounts in each zone are approximately the same
- Recently completed renewable projects have been modeled
- This resulted in some modifications in the MW amounts, type, and location of renewables within each zone

This policy study is focused on the Imperial Zone

- As noted in the ISO's 2015-2016 TPP Report, last year's studies were based on the transmission planning input provided by IID for its system in the spring of 2015
- In October 2015, IID provided new base cases modifying its future transmission plans as comments into the ISO's planning process
- The ISO's study timelines do not permit restarting the process within a given cycle and thus the 2015-2016 results did not take into account that information
- IID's input was taken into account in the 2016-2017 TPP studies

IID upgrades

- IID upgrades modeled in 2015-2016 TPP
  - Imperial Valley-Dixieland 230 kV line
  - Highline-El Centro Upgrade
  - Imperial Valley Policy Project (230 kV Liebert Switching Station and 230 kV transmission line connecting to Imperial Valley 230 kV substation, loop-in of IID's existing S-Line to new Fern 230 kV switchyard)
- Based on IID's revised input, none of the upgrades above were modeled in 2016-2017 TPP

Renewable generation

- 1572 MW in Imperial-SDG&E
- 417 MW in Imperial-IID
  - includes 240 MW of contracted solar (creating an expanded MIC)
  - plus 177 MW of additional potential renewable generation from the CPUC portfolio
  - this amount is in addition to existing geothermal
- 322 MW in Baja
- 330 MW in Arizona

Study Methodology

- Deliverability assessment was performed for the 33% base portfolio to test the deliverability of generation in the Imperial, Baja, and Arizona zones
- Study follows the same on-peak deliverability assessment methodology as used in generation interconnection studies

Objectives of Portfolio Deliverability Assessment

- Determine deliverability of the Target Maximum Import Capability (MIC)
  - Existing IID located generation was utilized to produce the Target MIC schedules and flows
  - IID located generation in the renewable portfolio was explicitly modeled and scheduled as an import over and above the initial MIC level
- Determine deliverability of renewable resources inside CAISO BAA
- Identify transmission upgrades needed to support full deliverability of the renewable resources and Target MIC

Import Assumptions

- Maximum summer peak simultaneous historical import schedules (2017 Maximum RA Import Capability)
  - IID Branch Group was modeled at 462 MW of target MIC. The 240 MW of expanded MIC and 177 MW of additional renewable generation from the portfolio was represented as explicitly modeled generation in IID and scheduled as additional imports to the ISO over and above the target MIC.
  - Historically unused Existing Transmission Contracts are initially modeled by equivalent generators at the tie point

Load and Transmission Assumptions

- ISO 2026 1-in-5 load
- Same transmission assumptions as reliability assessment
  - Existing transmission
  - Approved transmission upgrades

Preliminary study results

- Study results indicated a modest overload in testing the deliverability of the entire portfolio
- The overload is alleviated by a reduction of approximately 20 MW of renewable generation deliverability
- Given the modest shortfall in deliverability and the objective of reviewing reinforcement requirements when 50% policy renewable generation portfolios are available, mitigations are not recommended at this time for policy purposes but may be revisited in economic project evaluations

Overloaded Facility	Contingency	Flow
Imperial Valley-El Centro 230 kV intertie	Imperial Valley-North Gila 500 kV	102%

California ISO

Economic Planning- Preliminary results of congestion and economic assessments

Yi Zhang
Regional Transmission Engineer Lead

2016-2017 Transmission Planning Process Stakeholder Meeting
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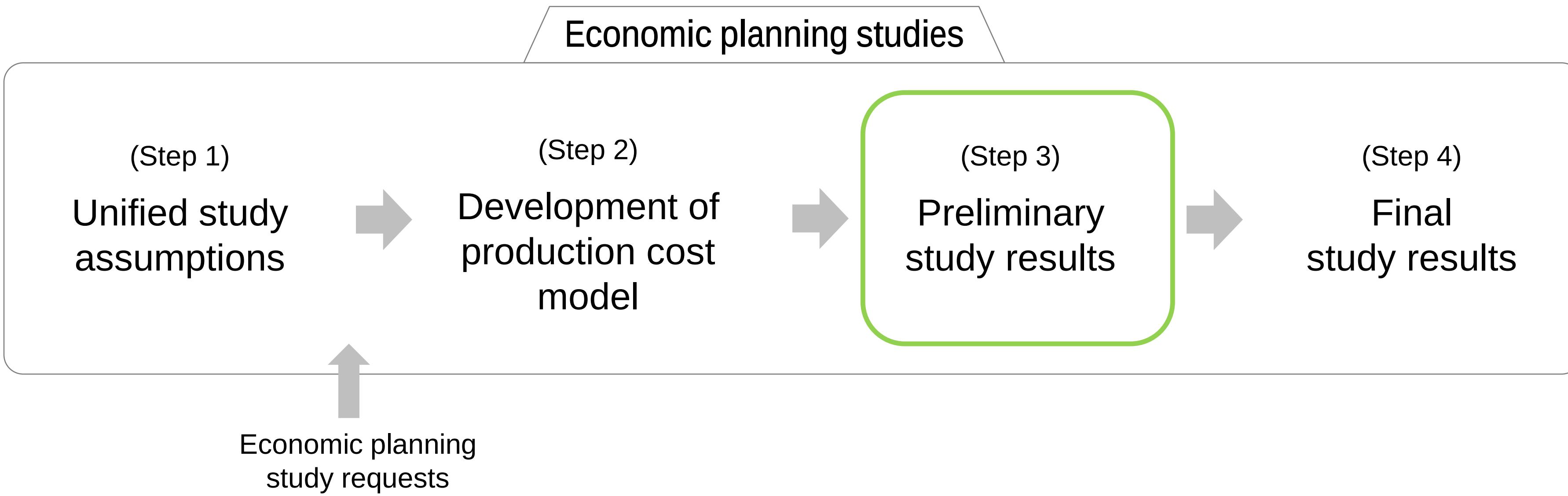
Steps of economic planning studies



Database development

- Starting point
  - TEPPC 2026 Common Case V1.3 released by TEPPC in August, 2016
- ISO's major updates since the last stakeholder meeting
  - Renewable generators that are required to meet 33% RPS, or that meet the requirements of ISO's planning assumptions
  - Validated changes in TEPPC CC v1.5, which was released by WECC on October 21, have been incorporated

Summary of congestions

Congestion area or branch group	Cost (M$)	Duration (Hour)
BOB SS (VEA) - MEAD S 230 kV line	28.73	593
Path 45	25.62	430
PG&E LCR	14.36	982
Path 26	7.60	377
PG&E/TID Exchequer	2.00	780
SDGE Miguel 500 kV transformer	1.17	96
J.HINDS-MIRAGE 230 kV line #1	1.02	186
SCE LCR	0.63	47
SDGE Suncrest - Sycamore 230 kV line	0.42	10
Path 15/CC	0.36	97
SDGE/CFE IV PFC	0.24	137
COI	0.33	38
Table MT - VacaDixon 500 kV	0.06	4
PG&E/Sierra MARBLE transformer	0.04	51
IID-SDGE	0.04	462
Inyo-Control	0.03	45
Path 24	0.01	13
N.Gila-Imperial Valley 500 kV line	0.01	1

High level observations – Path 26 and Path 15

- A noticeable change for Path 26 and Path 15 flows is that Diablo nuclear units are modeled off line in the 2026 Production Cost Model (PCM)
- Flow patterns on Path 26 in 2026 changed from previous years' studies, although the total congestion cost did not change significantly from previous cycles
  - About 90% of Path 26 congestion was observed on the direction from south to north due to renewable generation in southern California
- Path 15 congestion is almost unchanged from previous years' studies:
  - Diablo off line but more flow on Path 26 from south to north

High level observations – COI

- Planning nomograms for COI have been implemented
  - Refer to COI planning nomograms developed in ISO's 2013~2014 TPP
  - 500 kV outages/derates based on ISO's historical data were modeled
- The ISO is working with the owners of COI facilities to identify additional regular maintenance requirements that may cause derates; the maintenance may include:
  - Transmission facilities
  - Relay devices
- Will model additional forecast outages and derates that may cause or increase routine congestions

High level observations – Congestions around SDGE

- Path 45 congestion
  - Mainly from ISO to CFE due to renewable generation in Imperial Valley
  - Path 45 rating from ISO to CFE is modeled as 408 MW as in WECC 2016 Path Catalog
- Suncrest – Sycamore 230 kV line and Miguel 500 kV transformer congestions
  - Both are under N-1 contingencies on parallel lines or transformers; SPS could be used to mitigate congestions
- IID-SDGE 230 kV "S" Line congestions
  - Over 400 hours of congestion from IID's El Centro to SDGE's Imperial Valley
  - Under N.Gila – IV 500 kV line N-1 due to renewable generation in IID and east-to-west flows on N.Gila -IV 500 kV line

“S” line congestion identification (cont.)

- Alternative mitigation solutions to be considered:
  - Congestion management (no upgrade)
  - “S” Line reconductor, or 2nd Imperial Valley-El Centro 230 kV line
  - Back to Back DC, AC/DC conversion of SWPL
  - 2nd North Gila-Imperial Valley 500 kV upgrade, STEP Midway-Devers 500 kV AC Inter-tie and North Gila-Midway-Devers 500 kV AC Inter-tie Projects
  - The larger projects need analyses are likely to be dependent on the 50% RPS renewable development

High level observations – other congestions

- BOB SS (VEA) – Mead S 230 kV line
  - Congestion from BOB SS (ISO bus) to Mead S
  - Bob SS – Mead S is one of three lines between ISO buses and Mead S 230 kV bus, but has a much smaller rating than the other two
- PG&E North-Cost-North-Bay area LCR contingencies related congestion
  - Contingencies identified in LCR studies
  - The largest congestion was observed on Santa Rosa – Corona 115 kV line under contingency
  - Geothermal units in this area contribute to the congestion

Economic planning study requests

#	Study request	Areas
1	SWIP-North, COI and Path 26 congestions*	ID/NV
2	Blythe's Loop-in Project**	Southern CA
3	Eagle Mountain Pumped Storage Project ***	Southern CA
4	COI congestion ****	Northern CA
5	Path 15 study *****	Northern CA
6	Path 26 study ****	Northern CA/Southern CA

* SWIP-North will be studied in the interregional transmission planning process

** This project was studied extensively in the 2015-2016 planning cycle, and the ISO is not aware of material changes in circumstance

*** The Eagle Mountain pumped storage project and other pumped storage projects will be studied in the large energy storage special study

**** COI and Path 26 congestions are being investigated further, as discussed in this presentation

***** Path 15 congestion was studied in 2012~2013 planning cycle, and the congestion was not worse, therefore no further study is contemplated in this planning cycle

Next steps

- Perform detailed production cost simulations and economic assessments

- Review study requests, finalize list of economic studies being undertaken and perform economic assessments if needed

- Present the final results and recommendations in the fourth stakeholder meeting of 2016~2017 planning cycle

50% Special Study Update

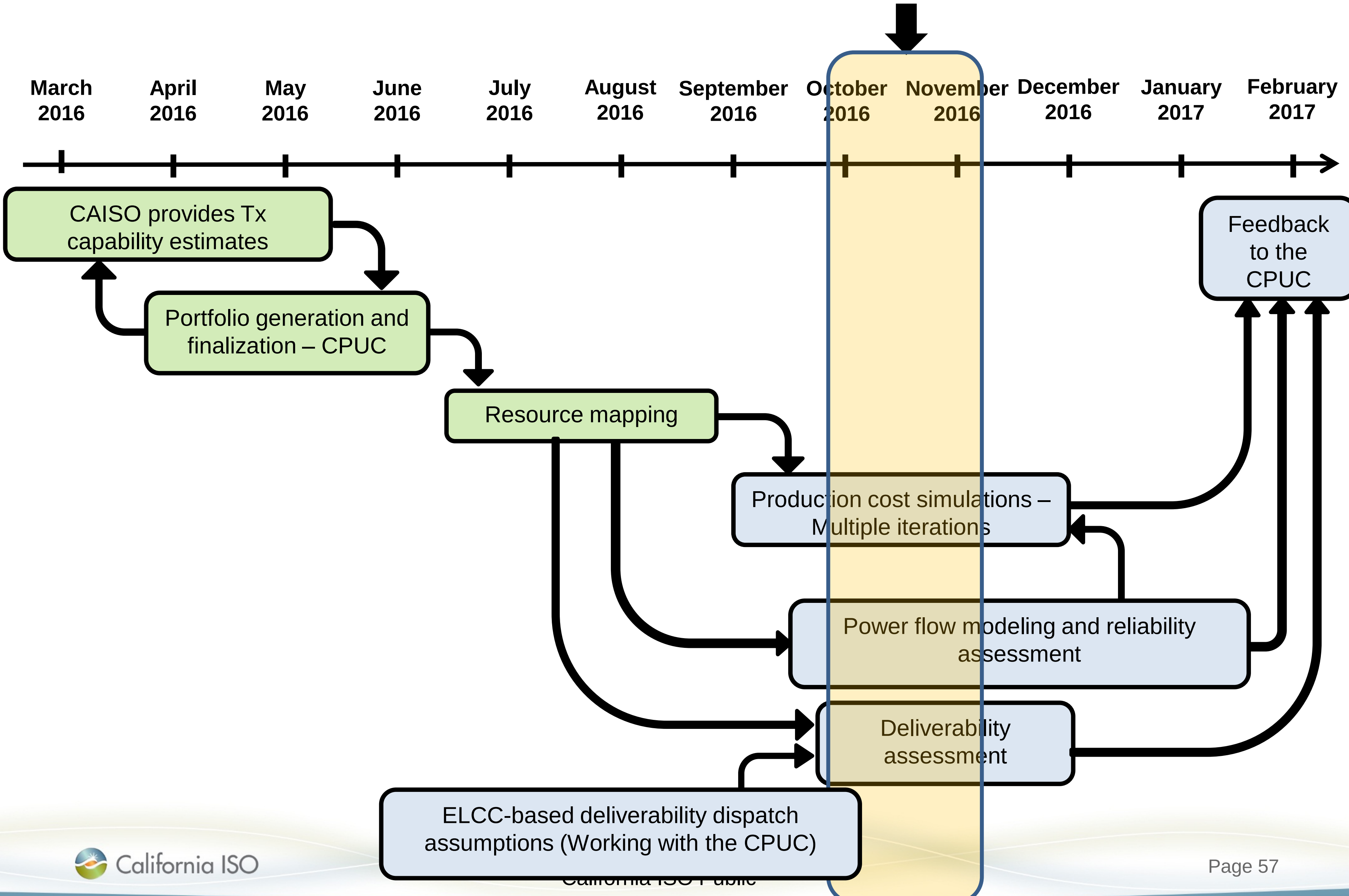
An information-only study performed as part of 2016-2017 Transmission Planning Process

Sushant Barave

Regional Transmission Engineer Lead

November 16, 2016

50% Special Study Timeline



Modeled Study Scenarios and Base Cases

Reliability Assessment

In-State FCDS portfolio | In-State EO portfolio | Out-of-State FCDS portfolio | Out-of-State EO portfolio

- Non-peak cases being used based on the snapshots identified during 2015-2016 TPP (Spring and Fall snapshots)
- Out-of-state portfolios will primarily be assessed for Southern CA (possible sensitivity for Northern CA of high COI flows and high imports from WY)
- All four portfolios are initially being studied without ITPs modeled in the base case
- As part of the preliminary ITP evaluation, we plan to run certain handpicked contingencies on the out-of-state portfolios

Status:

i. Resource modeling for six base cases (4 for SOCAL and 2 for Northern CA) is completed. NM resource locations selected. WY locations pending.

ii. Resource dispatch based on snapshots is in-progress

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Deliverability Assessment

In-State FCDS portfolio | Out-of-State FCDS portfolio

- Peak load scenarios to be assessed in line with the concept of deliverability
- Testing a new approach of applying ELCC based dispatch to evaluate deliverability of resources (<u>more details on the next slide</u>)

Status:

i. Resource modeling for the two peak cases (In-state and OOS) is completed

ii. ELCC based dispatch assumptions are being worked on

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Curtailment Analysis

All four portfolios

- Total renewable curtailment will be captured
- Transmission-related curtailment will be the focus
- Impact of import assumptions on curtailment may be examined

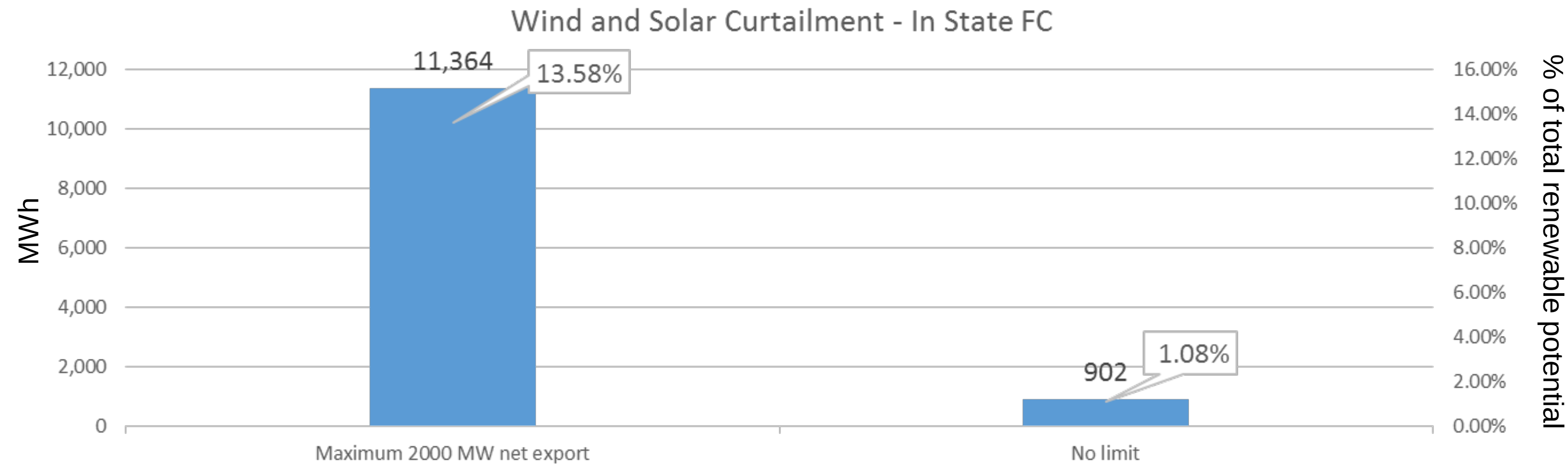
Status:

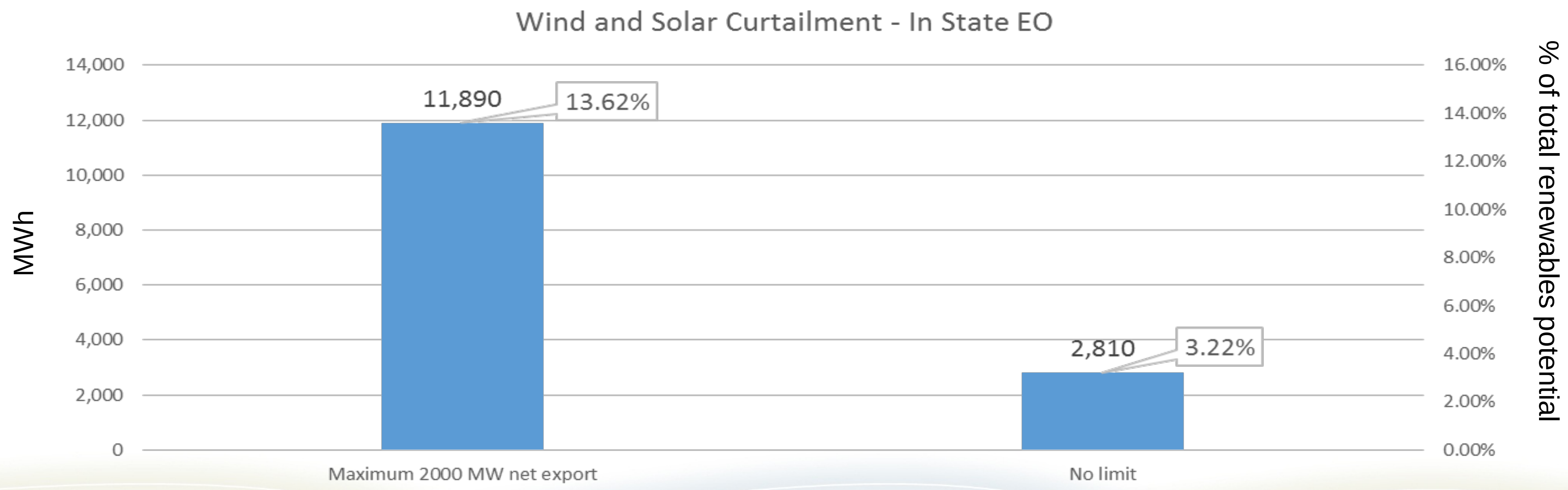
i. Enhancements to TEPPC common case completed (refer to Economic Planning presentation)

ii. In-state portfolio modeling and simulation completed

iii. Out-of-state modeling in-progress

Preliminary Curtailment Results – In-state Portfolios





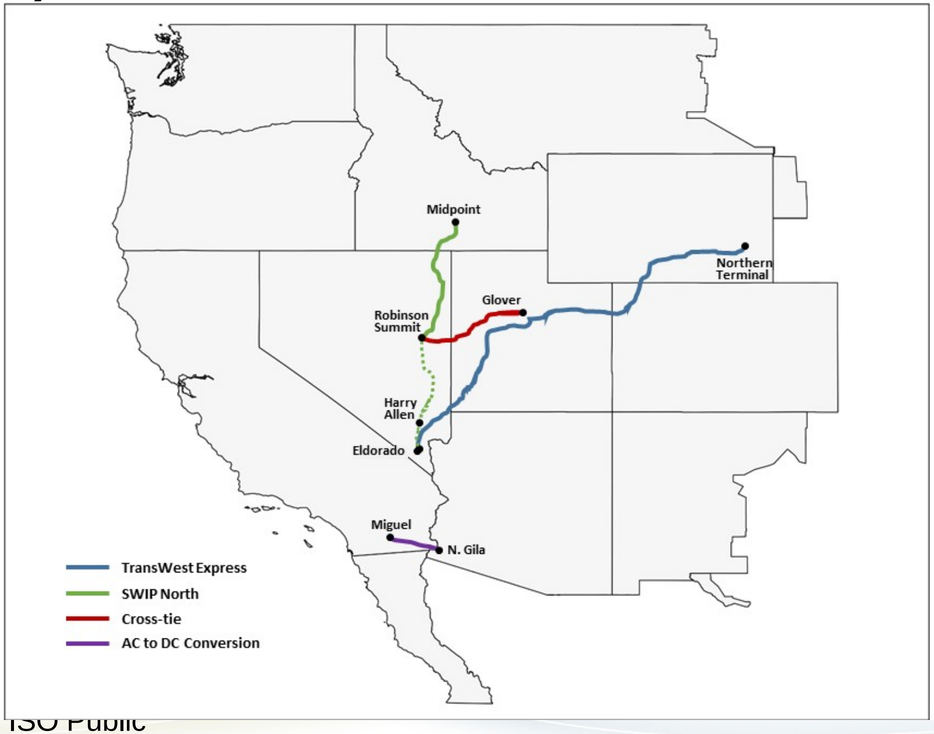
Interregional Coordination Update

- The California ISO is coordinating the California 50% scenario work with NTTG and WestConnect
- Resource mapping of 2,000 MW wind in NM is finalized based on data provided by NTTG
- Resource mapping of 2,000 MW wind in WY is being worked out with WestConnect.

Interregional Transmission Projects (ITPs)

- TransWest Express
  - *California ISO*
  - *NTTG*
  - *WestConnect*
- SWIP North
  - California ISO
  - *NTTG*
  - *WestConnect*
- Cross-tie Project
  - California ISO
  - *NTTG*
  - *WestConnect*
- AC/DC Conversion Project
  - *California ISO*
  - *WestConnect*

Relevant Planning Region



Deliverability Assessment Update

- Deliverability is an essential element of resource adequacy requirement. Resources need to be deliverable to load 'when needed'.
- First attempt to incorporate effective load carrying capacity (ELCC) data into deliverability assessment
- Trying to assess how might a potential ELCC-based resource procurement impact the deliverability study assumptions

CPUC's ELCC data analysis and estimation of exceedance values (ongoing work)

Peak Shift Identification → Renewable generation dispatch around the peak → Exceedance value determination → Deliverability assessment dispatch

Peak Shift Identification
- 35 years of hourly data (1980 – 2014) scaled to 2026
- BTM generation determined based on hourly weather pattern, technology and installed capacity
- Identified the peak shift

Renewable generation dispatch around the peak
- A 3-hour window around the shifted peak used to capture renewable output
- By technology, year, region and target month (May-Sept)

Exceedance value determination
- Percentile values for renewable output were calculated
- Renewable output in this 3 hour window was compared to nameplate

Deliverability assessment dispatch
- Dispatch assumption - (i) 50% exceedance value and/or (ii) 20% exceedance values

Next Steps

- Power flow assessment
  - Reliability studies
    - In-state FCDS: Northern CA and Southern CA snapshots
    - In-state EO: Northern CA and Southern CA snapshots
    - Out-of-state FCDS: Southern CA snapshot
    - Out-of-state EO: Southern CA snapshot

    For the out-of-state portfolios, possible sensitivity for Northern CA with high COI flows and high imports from WY may be assessed
  - Deliverability studies
    - Finalize ELCC based capacity value assumptions and dispatch the modeled renewables
    - Run deliverability assessment for the In-state and out-of-state

- Production cost simulation runs to capture transmission-related curtailment of renewables

- Draft results by stakeholder meeting #4 (February 2017)

- Feedback to the CPUC (February 2017)

Questions?

Gas-Electric Coordination Summer 2026 Transmission Planning Assessment for Various Gas Curtailment Scenarios with the Aliso Canyon Gas Storage Outage

David Le
Senior Advisor, Regional Transmission Engineer
Regional Transmission South

2016-2017 Transmission Planning Process Stakeholder Meeting
November 16, 2016

Overview - Southern California discussion

- Background information and current status

- Background information on the need for assessment of long-term viability of natural gas storages in California

- Summary gas-electric coordination summer 2026 transmission planning assessment for various gas curtailment scenarios with the Aliso Canyon gas storage outage

- Next steps

Background Information

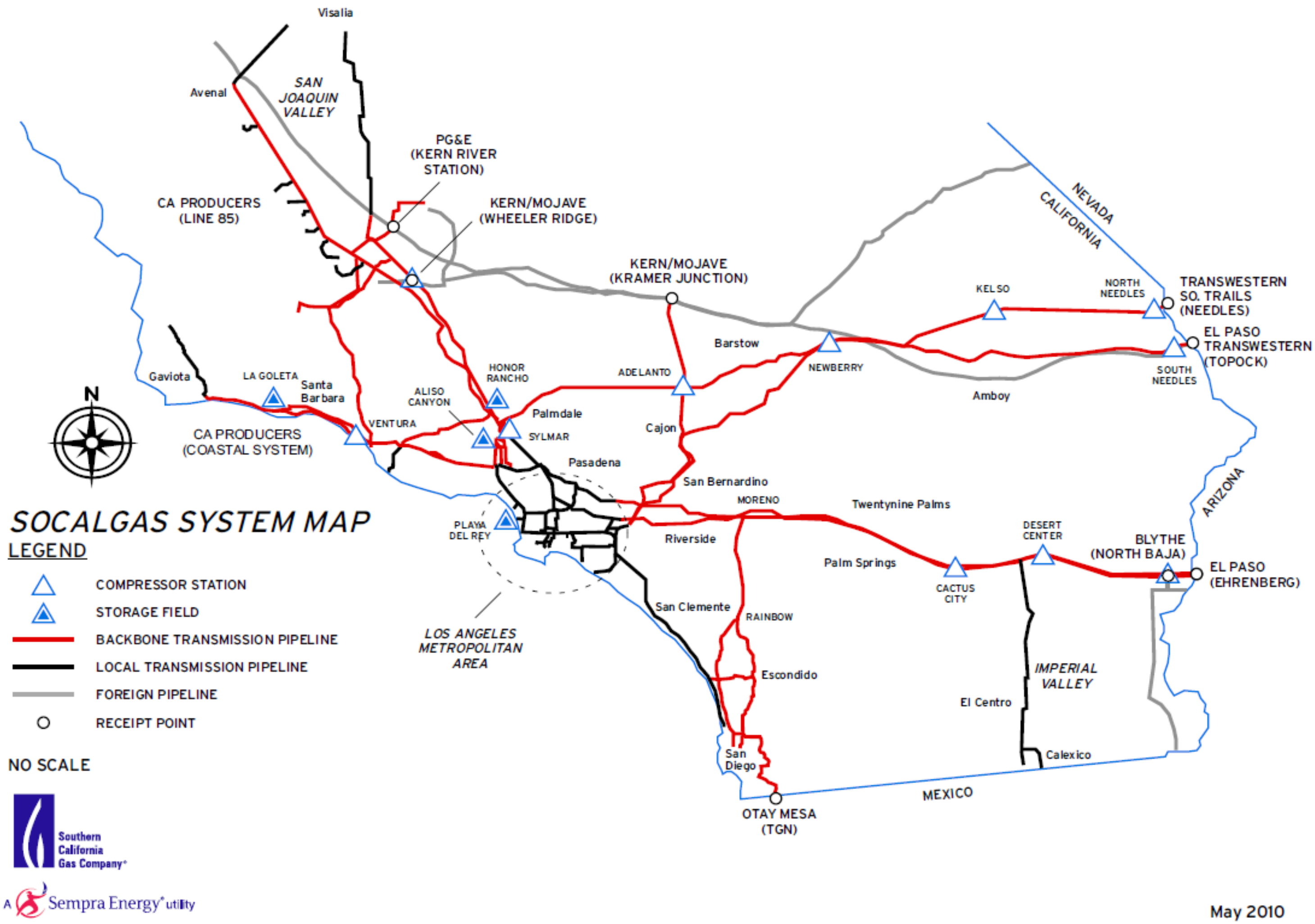
The Aliso Canyon gas storage constraint and its importance to southern California reliability

- Aliso Canyon is the largest gas storage field
  - Inventory capacity of 86.2 Bcf
  - Withdrawal capacity at 1,860 MMcfpd
  - Typically used during summer time to provide hourly peak electric generation demands throughout the day, which cannot be met with pipeline supplies because of the magnitude and speed that these peak demand require
  - Currently holds about 15 Bcf of storage under moratorium of new injections until comprehensive review and inspection of storage wells is completed
- In April 2016, the Reliability Task Force, consisting of the CEC, CPUC, ISO, and LADWP with participation from SoCal Gas Company completed the Aliso Canyon Risk Assessment Technical Report, quantifying the potential impacts to electric generation under various gas curtailment scenarios with the Aliso Canyon gas storage outage constraint for the summer 2016 time frame.

The Aliso Canyon gas storage constraint and its importance to southern California reliability (cont'd)

- On August 26, 2016, the Reliability Task Force completed the Aliso Canyon Winter Risk Assessment Technical Report and the Gas and Electric Reliability Winter Action Plan. An Independent Review of Hydraulic Modeling for Aliso Canyon Risk Assessment was also provided.
- At the ISO 2016-2017 Transmission Planning Process Stakeholder Meeting on September 21 and 22, 2016, the Gas-Electric Coordination Summer 2017 Transmission Planning Assessment for Various Gas Curtailment Scenarios with the Aliso Canyon Gas Storage Outage was presented.

Directly Affects 17 Gas-fired Plants Generating ~9800MW; Indirectly Affects 48 Plants Generating 20,120MW



Current Status

- Significant risk remains
- 15 Bcf remains in the Aliso field
- Safety review is continuing
- Unknown when SoCalGas will apply to begin injections; cleared wells may produce less due to influx of liquids
- As of October 28, 2016, there are 28 wells that passed all test. The field has a total of 114 wells.
- SoCalGas must retain enough wells to withdraw 420 mmcfd through summer
- 21 mitigation measures were implemented for summer
- Made it through heat events in June and in July, thanks to combination of good planning (with mitigation measures) and luck (with weather better than forecast)

Background information on the need for assessment of long-term viability of natural gas storage in California

- Provision 14 of the Governor’s Proclamation of a State of Emergency, issued on January 6, 2016, stated that:
  - *The Division of Oil, Gas and Geothermal Resources, the California Public Utilities Commission, the California Air Resources Board and the California Energy Commission shall submit to the Governor's Office a report that assesses the <u>long-term viability of natural gas storage facilities in California</u>. The report should address operational safety and potential health risks, methane emissions, <u>supply reliability for gas and electricity demand in California</u>, and the role of storage facilities and natural gas infrastructure in the State's long-term greenhouse gas reduction strategies.*
- The CEC 2016 Integrated Energy Policy Report (IEPR) Update Final Scoping Order identified the need for:
  - *Assessment of long-term solutions to provide reliable natural gas and electricity service in the Los Angeles Basin if Aliso Canyon is not available or has limited availability.*

Summer 2026 Transmission Planning Assessment for Various Gas Curtailment Scenarios

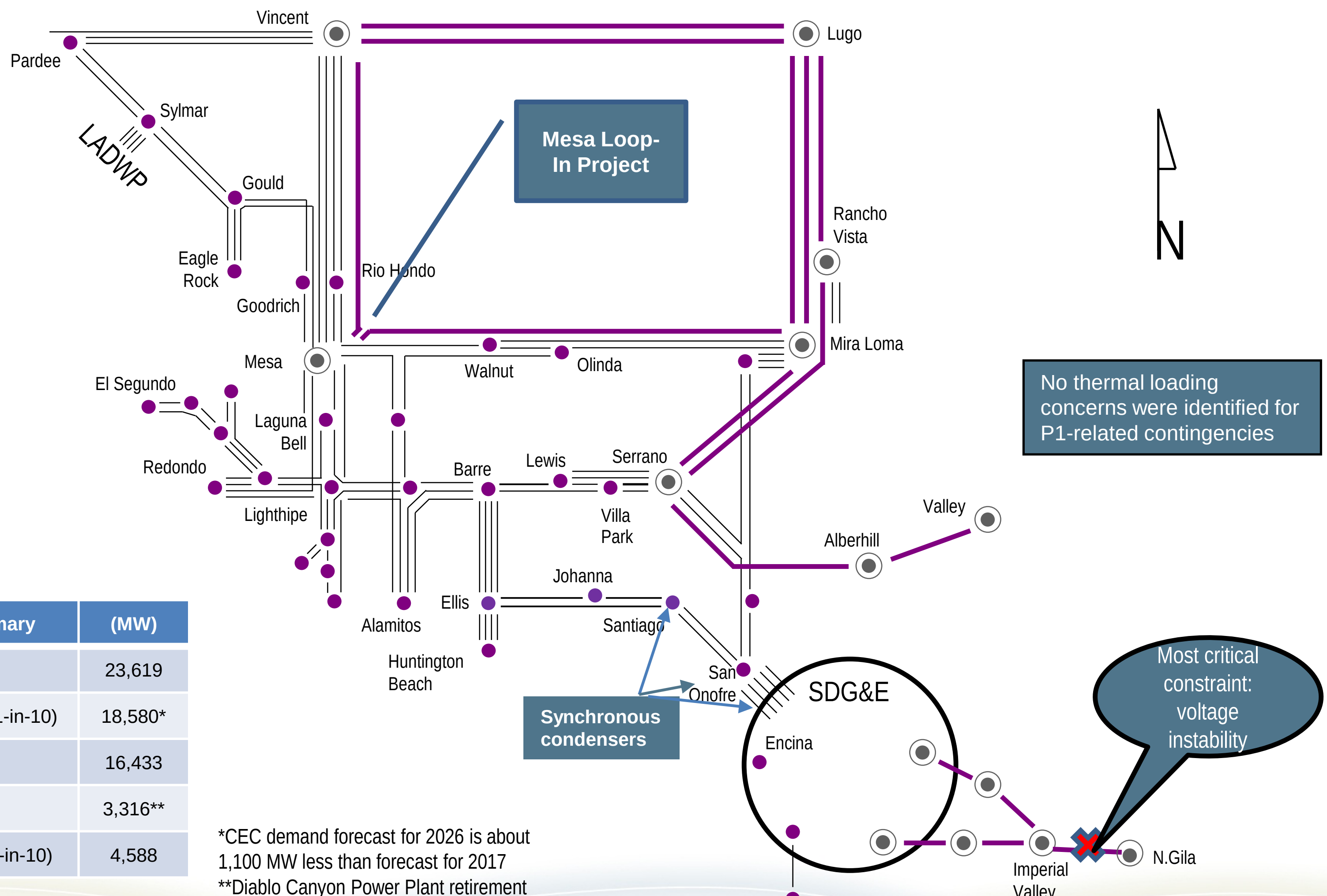
Reliability assessment for minimum generation requirement for the LA Basin and San Diego areas

- Study was performed similar to the Joint Agency Task Force technical assessment for summer 2016 and the ISO transmission planning assessment for summer 2017.
- Minimum generation in the LA Basin and San Diego areas was evaluated to maintain operational reliability for the normal conditions and for the next contingency (i.e., NERC P0 and P1 reliability criteria as performed for the Joint Agency Task Force technical assessment).
- Gas burns required for meeting minimum generation were compared with net amount of actual gas burns that occurred on Sept. 9, 2015, minus gas curtailment amount due to the following major gas facility outage scenarios:
  - Scenario 1 – Aliso Canyon gas storage unavailable; supply shortfall of 150 MMcfpd of gas between scheduled and actual gas flows
  - Scenario 2 – Scenario 1 plus a non-Aliso Canyon gas storage outage, reducing 400 MMcfd of system capacity
  - Scenario 3 – Scenario 1 plus a major gas pipeline outage reducing 500 MMcfd of system capacity
  - Scenario 4 – Combination of Scenarios 1, 2 and 3 resulting in an overall reduction of 900 MMcfd of system capacity.

Reliability assessment for minimum generation requirement for the LA Basin and San Diego areas (cont'd)

- Due to assumptions of significant penetration of the behind-the-meter photovoltaic distributed generation (BTM PVDG) for the ten-year horizon, the ISO also evaluated a sensitivity scenario in which the utilities' peak loads are shifted to early evening hours (i.e., 6 p.m.) when solar generation contribution is not available.
- The following is a summary of the peak load impact values of the photovoltaic distributed generation that the CEC forecast for 2026 timeframe.
  - Total for SCE service area: 1,739 MW
  - Total for SDG&E service area: 504 MW
- The CEC demand forecast for 2026 is less than its demand forecast for 2017 timeframe
  - 1100 MW less for the LA Basin
  - 280 MW less for San Diego area
- In addition to the CPUC-approved long term procurement for the LA Basin and San Diego local areas, the ISO also included expedited battery energy storage system (BESS) that were approved recently by the CPUC related to the Aliso Canyon gas constraint as well as battery storage from the long-term procurement plan
  - 72 MW (expedited) and 264 MW (LTPP) for SCE service area
  - 37.5 MW (expedited) for SDG&E service area

Identified reliability concerns with minimum generation in the LA Basin and San Diego areas (CEC peak demand forecast with BTM PVDG)



Load / Flow Summary	(MW)
Total SCE load	23,619
Total LA Basin load (1-in-10)	18,580*
Total SCIT	16,433
Path 26 Flow	3,316**
Total SDG&E load (1-in-10)	4,588

*CEC demand forecast for 2026 is about 1,100 MW less than forecast for 2017
**Diablo Canyon Power Plant retirement affects Path 26 maximum flow

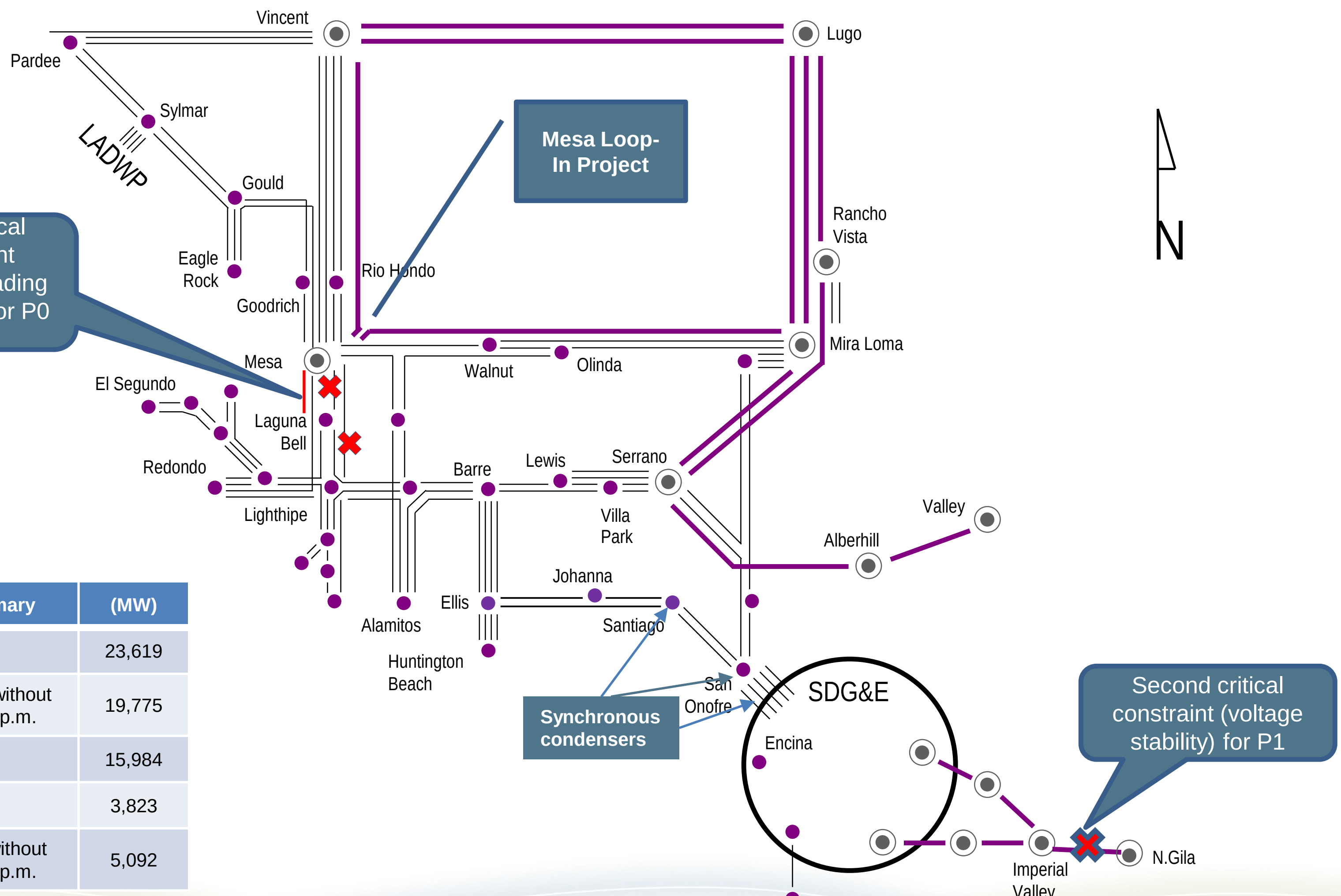
Electric generation impact due to gas curtailments under various gas outage scenarios for the most critical transmission reliability concern (for CEC demand forecast with BTM PVDG)

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	Description	Formula	Scenario 1: Aliso Canyon Gas Storage Outage	Scenario 2: With Other Storage Outage	Scenario 3: With Major Pipeline Outage	Scenario 4: Overlapping Outages (1+2+3)
1	Original Curtailment for day - Volume by SCG (MMcfd) (Calculated by SCG)		180	480	600	1,100
2	Number of Hours of Curtailment		8	8	8	8
3	Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)	(Row 1/24)*1.4*Row 2	84	224	280	513
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf) **for the most critical transmission constraint**	3505 MW*8 hours/103 MWh/MMcf	272	272	272	272
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Row 4 + Row 5	396	396	396	396
7	Actual ISO SCG system September 9, 2015 Gas Burn (MMcf)		760	760	760	760
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns		923	923	923	923
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	410
11	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf)	Row 10 - Row 6	443	303	247	13
12	ISO+LADWP Energy Conversion of Gas Burn Short/Surplus for the day (MWh)	Row 11*103MWh/MMcf	45,607	31,187	25,419	1,386
13	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	Row 12/Row 2	5,701	3,898	3,177	173
14	Customer Impacted	Row 13*700	0	0	0	0

ISO Board-approved transmission projects help mitigate local transmission reliability impact caused by Aliso Canyon gas storage outage constraint for the long term horizon

- Coupled with lower demand forecast, the following ISO Board-approved transmission projects help alleviate transmission reliability concerns caused by Aliso Canyon gas outage constraint
  - Addition of 1,815 MVAr of dynamic reactive support projects (i.e., synchronous condensers) at key locations in the Orange County and San Diego areas (Santiago, San Onofre, San Luis Rey, Talega and Miguel substations)
  - Mesa 500/230 kV Loop-In project in the LA Basin (three-AA transformer banks option)
- It is noted that the Mesa 500/230 kV Loop-In project is currently undergoing environmental review process at the CPUC. Its in-service date of December 2020 may be subject for delay if a permit to construct is not approved by December 2016 timeframe.
- The analyses indicated that all four considered gas facility outage scenarios have no gas burn deficiencies provided that the approved transmission projects are implemented

Identified reliability concerns with minimum generation in the LA Basin and San Diego areas (sensitivity scenario analysis of the CEC peak demand shifted to early evening at 6 p.m. without BTM solar DG contribution)



Load / Flow Summary	(MW)
Total SCE load	23,619
Total LA Basin load without BTM solar DG at 6 p.m.	19,775
Total SCIT	15,984
Path 26 Flow	3,823
Total SDG&E load without BTM solar DG at 6 p.m.	5,092

Electric generation impact due to gas curtailments under various gas outage scenarios for the most critical transmission reliability concern (CEC demand forecast without BTM PVDG)

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	Description	Formula	Scenario 1: Aliso Canyon Gas Storage Outage	Scenario 2: With Other Storage Outage	Scenario 3: With Major Pipeline Outage	Scenario 4: Overlapping Outages (1+2+3)
1	Original Curtailment for day - Volume by SCG (MMcfd) (Calculated by SCG)		180	480	600	1,100
2	Number of Hours of Curtailment		8	8	8	8
3	Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)	(Row 1/24)*1.4*Row 2	84	224	280	513
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf) **for the most critical transmission constraint**	4380 MW*8 hours/103 MWh/MMcf	340	340	340	340
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Row 4 + Row 5	464	464	464	464
7	Actual ISO SCG system September 9, 2015 Gas Burn (MMcf)		760	760	760	760
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns		923	923	923	923
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	410
11	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf)	Row 10 - Row 6	375	235	179	-55
12	ISO+LADWP Energy Conversion of Gas Burn Short/Surplus for the day (MWh)	Row 11*103MWh/MMcf	38,602	24,182	18,414	-5,620
13	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	Row 12/Row 2	4,825	3,023	2,302	-702
14	Customer Impacted	Row 13*700	0	0	0	491,709

Electric generation impact due to gas curtailments under various gas outage scenarios for the second critical transmission reliability concerns (provided the first constraint is mitigated)

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	Description	Formula	Scenario 1: Aliso Canyon Gas Storage Outage	Scenario 2: With Other Storage Outage	Scenario 3: With Major Pipeline Outage	Scenario 4: Overlapping Outages (1+2+3)
1	Original Curtailment for day - Volume by SCG (MMcfd) (Calculated by SCG)		180	480	600	1,100
2	Number of Hours of Curtailment		8	8	8	8
3	Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)	(Row 1/24)*1.4*Row 2	84	224	280	513
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf) **for the most critical transmission constraint**	3988 MW*8 hours/103 MWh/MMcf	310	310	310	310
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Row 4 + Row 5	434	434	434	434
7	Actual ISO SCG system September 9, 2015 Gas Burn (MMcf)		760	760	760	760
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns		923	923	923	923
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	410
11	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf)	Row 10 - Row 6	405	265	209	-24
12	ISO+LADWP Energy Conversion of Gas Burn Short/Surplus for the day (MWh)	Row 11*103MWh/MMcf	41,741	27,321	21,553	-2,480
13	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	Row 12/Row 2	5,218	3,415	2,694	-310
14	Customer Impacted	Row 13*700	0	0	0	217,029

thermal loading and voltage stability concerns were identified in the peak load shift to early evening scenario

- For the sensitivity assessment with the peak load shifted to early evening timeframe (i.e., 6 p.m.), the following reliability concerns were identified:
  - Primary constraint was identified with thermal loading concerns for the Mesa – Laguna Bell 230 kV #1 line under P0 (normal) and P1 (single element) contingencies
  - Secondary constraint was identified with post-transient voltage instability for the P1 contingency of Imperial Valley – North Gila 500 kV line
- Gas burn deficiency was identified for Scenario 4
- No gas burn deficiency was identified for the other three gas outage scenarios (i.e., Scenarios 1 – 3) provided that the Mesa Loop-In project and the dynamic reactive support projects (i.e., synchronous condensers) are implemented.

Summary of Findings

- The potential impact to electric generation due to various gas curtailment scenarios for summer 2026 exhibits the following trends
  - Major ISO Board-approved transmission projects (i.e., Mesa Loop-In and synchronous condensers in Orange County and San Diego areas), coupled with the CEC lower demand forecast, help mitigate reliability concerns due to various gas outage scenarios related to Aliso Canyon gas storage outage
  - Using the CEC demand forecast with behind-the-meter photovoltaic solar generation, coupled with the above transmission projects, resulted in no gas burn deficiency for all four considered gas outage scenarios.
  - Scenarios with peak demand shifted to early evening hours without contribution from behind-the-meter photovoltaic generation indicated thermal loading and voltage stability concerns. This could cause gas burn deficiency for the extreme gas outage scenario (i.e., Scenario 4).

Next steps

- The ISO will include additional analyses for potential electric generation impact for the four considered gas outage scenarios for overlapping (P6) and common corridor (P7) contingencies in the transmission plan for medium and long-term local capacity requirement assessments.

2016-2017 TPP Gas-Electric Coordination Study– Northern California

Binaya Shrestha
Regional Transmission Engineer Lead
Regional Transmission North

2016-2017 Transmission Planning Process Stakeholder Meeting
November 16, 2016

2016-2017 TPP Northern California Gas-Electric Coordination Study Scope

- Gather information about gas system, capacity and supply network to gas-fired power plant in Northern California.
- Investigate plausible conditions which could result in gas curtailment to power plant resulting in significant reduction in electric generation.
- To the point such conditions are identified, perform studies to identify any adverse impact to electric system reliability.

Backbone – Pipeline Capacity

Line 400/401

- Firm Capacity = 2038 mmcfd

Line 300

- Firm Capacity = 1010 mmcfd

INTERCONNECT SUPPLY CAPACITY (mmcfd)	
Redwood Path	
From Gas Transmission Northwest	2,180
From Ruby	1,500
Baja Path	
From KRGT - HDL	282
From KRGT - Daggett	375
From Southern Trails	120
From El Paso Natural Gas	1,140
From Transwestern	365

Backbone – Storage Capacity

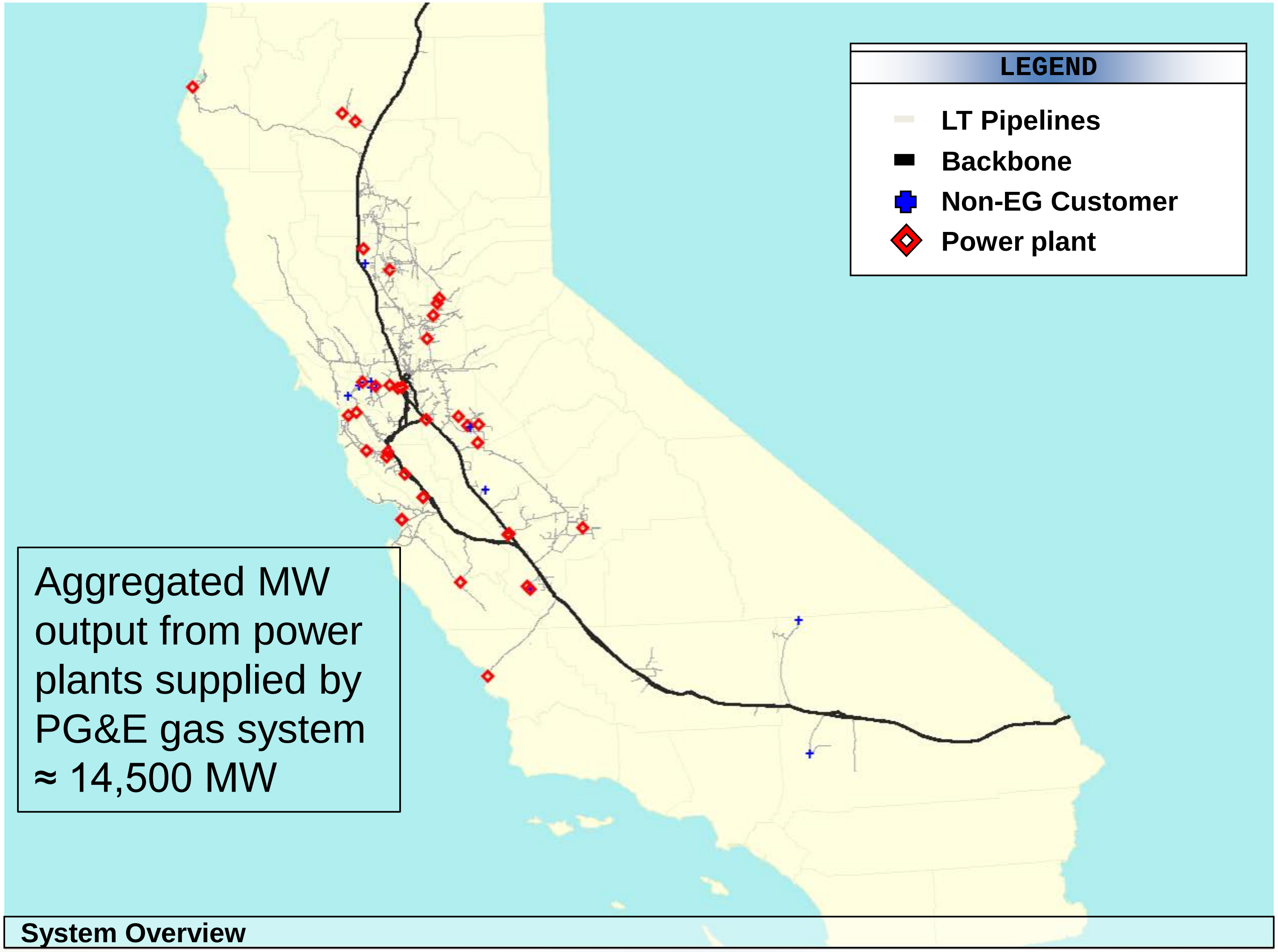
PG&E Storage Capacity

	Working Inventory (Bcf)	Supply (MMscf/d)
Total 2016	**105**	**2,105**
McDonald Island	82	1,580
Los Medanos	16	355
Pleasant Creek	2	70
Gill Ranch	5	100

Independent Storage Providers (ISPs)

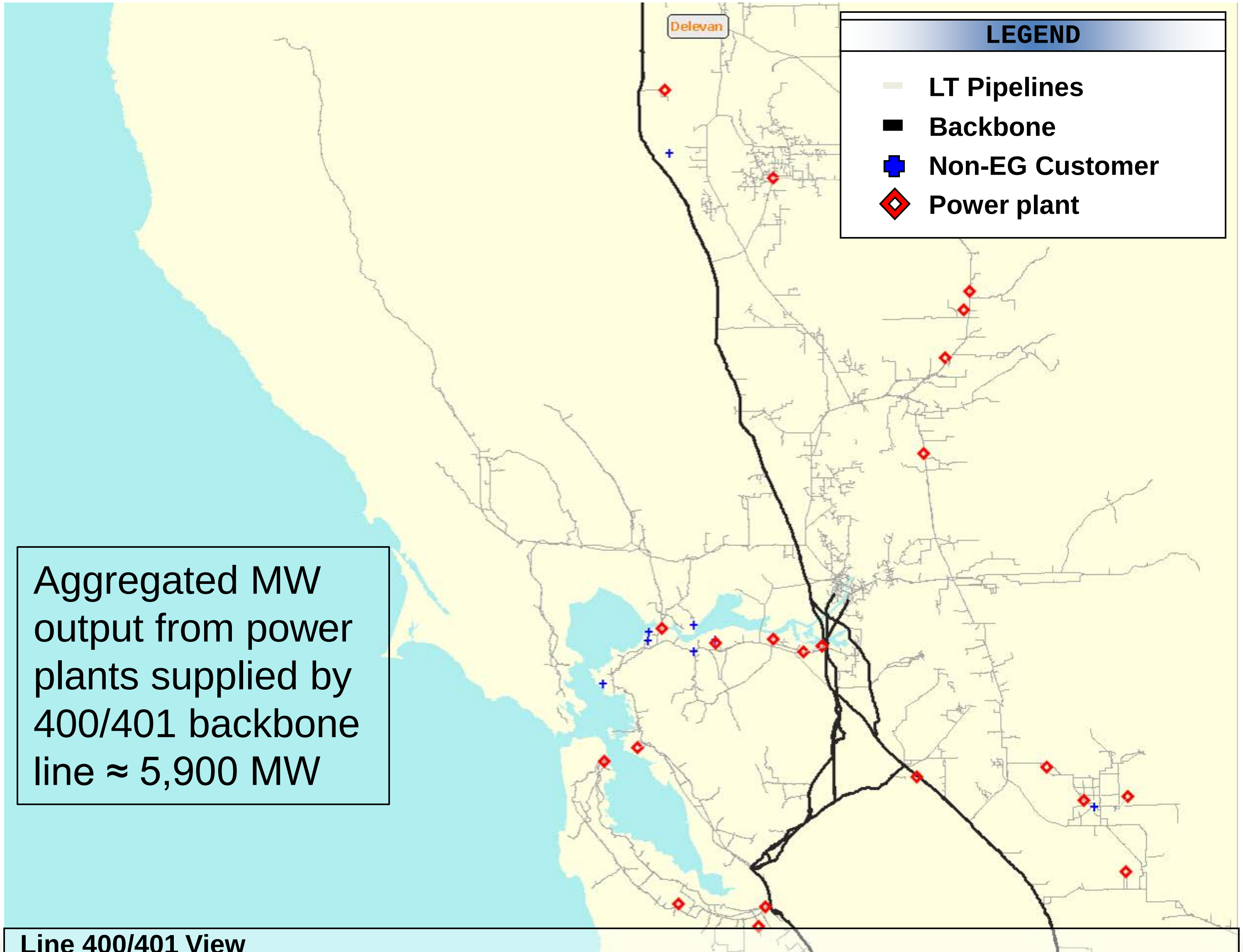
	Working Inventory (Bcf)	Supply (MMscf/d)
Total 2016	**133**	**2,300**
Wild Goose	75	950
Lodi Storage	32	750
Central Valley Storage	11	300
Gill Ranch Storage (75%)	15	300

Gas-fired Power Plant Location



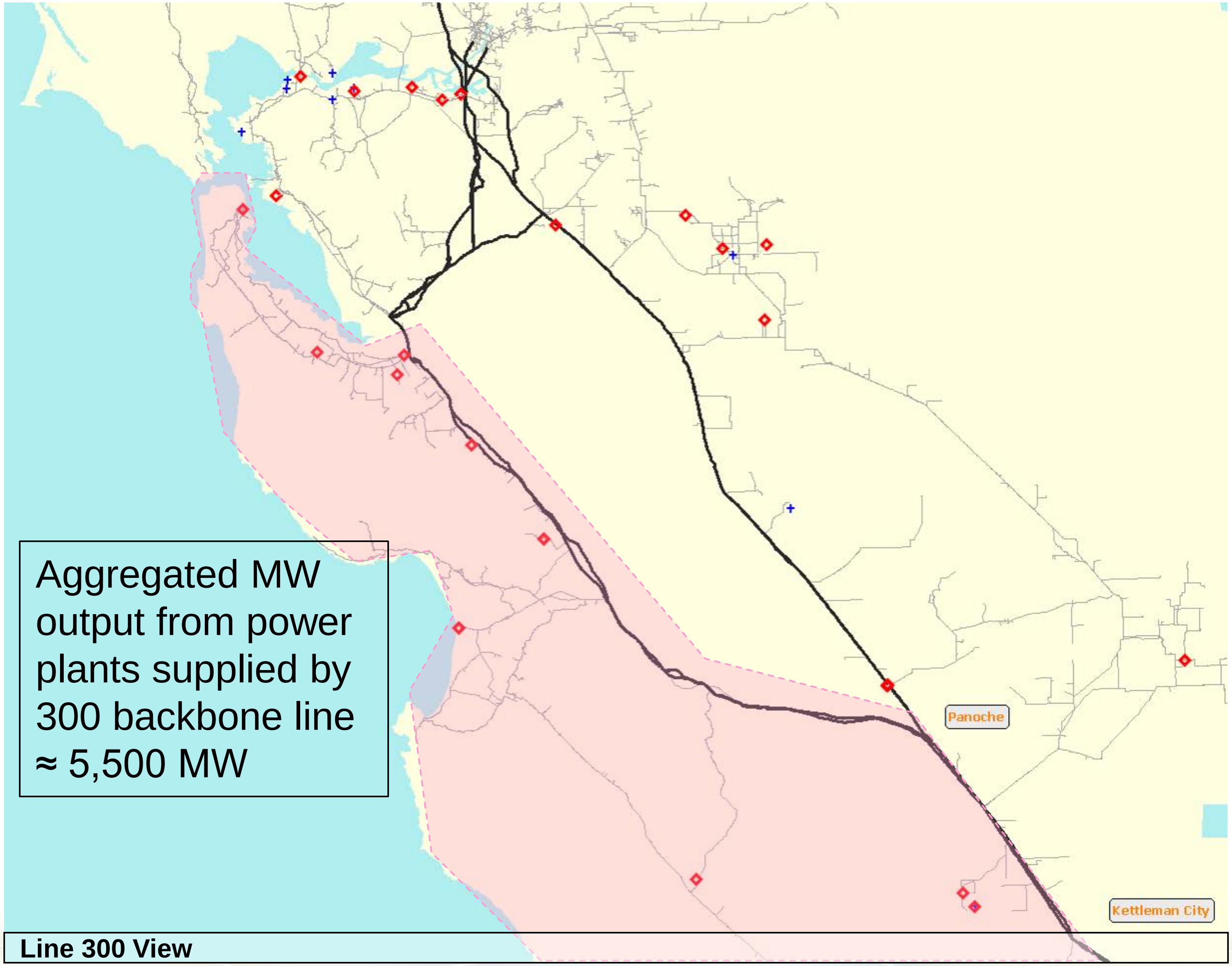
Aggregated MW output from power plants supplied by PG&E gas system ≈ 14,500 MW

Gas-fired Power Plant – Line 400/401 View



Aggregated MW output from power plants supplied by 400/401 backbone line ≈ 5,900 MW

Gas-fired Power Plant – Line 300 View

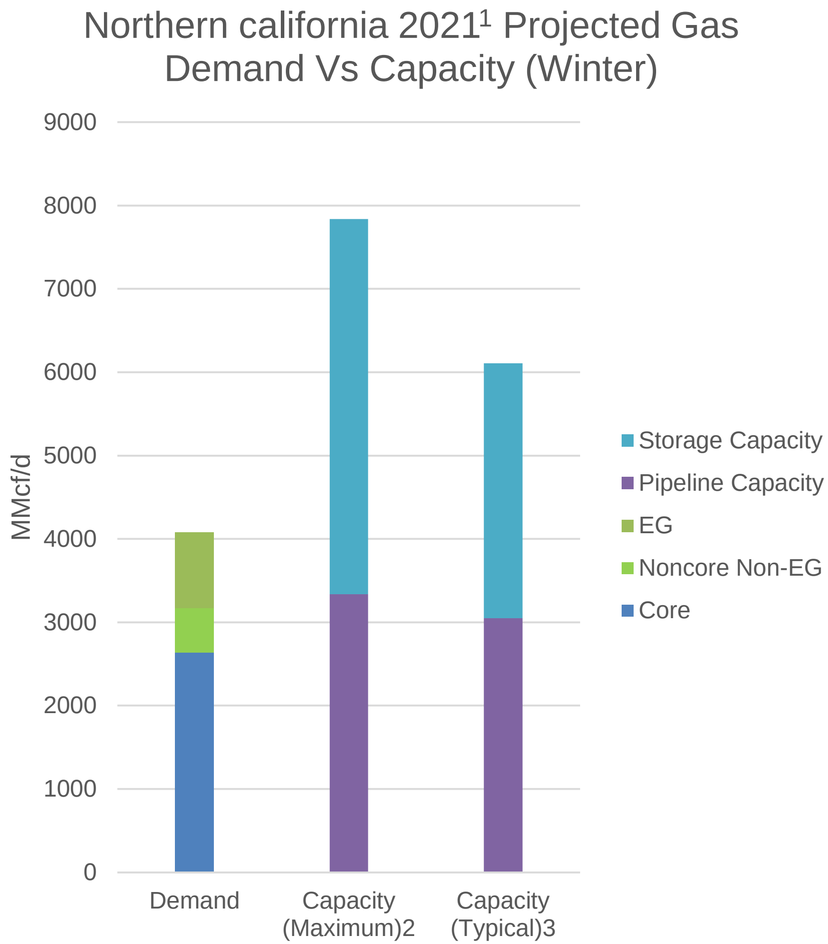


Gas-fired Power Plant – Kern River-Mojave

Aggregated MW output from power plants supplied by Kern River-Mojave gas system ≈ 2,200 MW (PG&E service area) and ≈ 1,600 MW (SCE service area)

Source: https://www.gljpublications.com/maps/mojave.gif

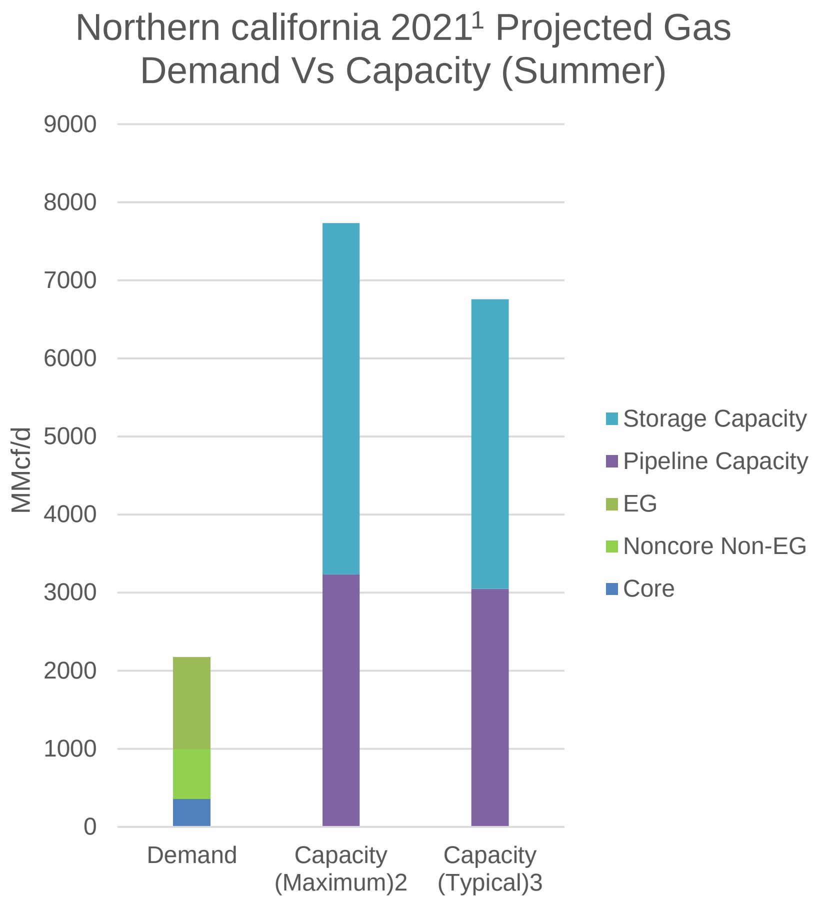
Gas Demand Vs Capacity (Winter)



- The combined pipeline and storage facilities provide sufficient capacity to serve demand under normal and constrained conditions.
- No direct relationship between power plants and storage facilities.

Note 1: Source – 2016 California Gas Report.
2: Source – California Gas Transmission Pipe ranger
3: Source – PG&E 2015 Gas Transmission and Storage Rate Case Prepared Testimony (for PG&E storage facilities)

Gas Demand Vs Capacity (Summer)



- The combined pipeline and storage facilities provide sufficient capacity to serve demand under normal and constrained conditions.
- No direct relationship between power plants and storage facilities.

Note 1: Source – 2016 California Gas Report.
2: Source – California Gas Transmission Pipe ranger
3: Assumed half the capacity for McDonald Island

Historical Gas Facility Outages and Impact on Power Plant Generation

- Based on the historical data, there has been no significant curtailment situations that impacted operation of gas-fired power plants.

Critical Areas and Local Capacity Requirements

Critical Areas	Total Generation In the Area (MW) (a)	Aggregated Max Output From Gas-fired Power Plants (MW) (b)	P1/P3 Contingency LCR (c)	Minimum Thermal Generation Needed for LCR[1] (c-(a-b))
Humboldt	218	163	110	55
Sierra (Pease subarea)	106	105	100	99
Greater Bay Area	9862	9500	4260	3898
Fresno	3303	914	1760	-
Stockton	598	390	340	132

Note 1: Assumes all non gas-fired generators are available.

Humboldt LCR Area

Total Generation In the Area: 218 MW

Aggregated Max Output From Gas-fired Power Plants: 163 MW

P1/P3 Contingency LCR: 110 MW

Minimum Thermal Generation Needed for LCR: 55 MW

- Humboldt power plants are dual fuel, gas curtailment doesn’t impact electric generation.
- No risk of not meeting LCR due to gas constrained conditions.

Sierra (Pease) LCR Subarea

Total Generation In the Area: 106 MW

Aggregated Max Output From Gas-fired Power Plants: 105 MW

P1/P3 Contingency LCR: 100 MW

Minimum Thermal Generation Needed for LCR: 99 MW

- The three thermal power plants in this area are primarily fed from same gas transmission line.
- If the upstream pipeline feeding these plants is unavailable to supply gas, the downstream feed will not have enough capacity to serve the three plants. There will be sufficient supply to run one of the plants from the downstream in summer.
- There is risk of not meeting LCR due to gas constrained conditions.

Greater Bay Area LCR Area

Total Generation In the Area: 9862 MW

Aggregated Max Output From Gas-fired Power Plants: 9500 MW

P1/P3 Contingency LCR: 4260 MW

Minimum Thermal Generation Needed for LCR: 3898 MW

- There are many thermal power plants connected to many different pipelines.
- There will be enough gas supply for minimum local generation under an abnormal demand and plausible facility outage conditions due to redundancy in the system.
- There is no significant risk of not meeting LCR due to gas constrained conditions.

Fresno LCR Area

Total Generation In the Area: 3303 MW

Aggregated Max Output From Gas-fired Power Plants: 914 MW

P1/P3 Contingency LCR: 1760 MW

Minimum Thermal Generation Needed for LCR: 0 MW

- There are enough non-thermal generation to meet LCR requirement.
- There is no significant risk of not meeting LCR due to gas constrained conditions.

Stockton LCR Area

Total Generation In the Area: 598 MW

Aggregated Max Output From Gas-fired Power Plants: 390 MW

P1/P3 Contingency LCR: 340 MW

Minimum Thermal Generation Needed for LCR: 132 MW

- The thermal power plant in Stockton LCR area is fed off of transmission line which can be fed from both directions, so an outage in on either side will most likely not have an impact. However, a severe outage right at the power plant location, the plant could lose its feed.
- There is no significant risk of not meeting LCR due to gas constrained conditions.

Review of Approved Projects –North Area

Jeff Billinton

Manager - Regional Transmission -North

November 16, 2016

2016-2017 Transmission Planning Process Stakeholder Meeting

Approach to Project Review

- ISO is conducting a review of the currently approved transmission projects in the 2016-2017 transmission planning process
- Focus is primarily on load growth driven projects, and projects approved prior to the revised transmission planning process (2010-2011)
- Base Cases
  - Local planning cases base case using the load and assumptions for 2026 with the 2016 transmission topology
    - Sensitivity for the peak shift (PV off)
    - Sensitivity with peak shift and no AAEE

Approach to Project Review *(continued)*

- The assessment includes the review of need for:
  - Reliability
  - Deliverability for generators
  - Local capacity requirement
  - Operational issues

- If there is still a need to be mitigated, the project will be reviewed if it is still the appropriate mitigation

Projects Identified where Mitigation No Longer Needed

- Central Valley Area
  - Mosher Transmission Project
  - Pease-Marysville #2 60 kV Line
- Greater Bay Area
  - Christie 115/60 kV Transformer No. 2
  - Almaden 60 kV Shunt Capacitor
  - Evergreen-Mabury Conversion to 115 kV
  - Monta Vista – Los Gatos – Evergreen 60 kV Project
  - Lockheed No. 1 115 kV Tap Reconductor
  - Mountain View/Whisman-Monta Vista 115 kV Reconductoring
  - Stone 115 kV Back-tie Reconductor
- Fresno
  - Kearney - Kerman 70 kV Line Reconductor
  - Cressey - North Merced 115 kV Line Addition

Projects Identified where Mitigation No Longer Needed *(continued)*

- Kern Area
  - San Bernard – Tejon 70 kV Line Reconductor
  - Taft-Maricopa 70 kV Line Reconductor

- Central Coast & Los Padres Area
  - Natividad Substation Interconnection
  - Soledad 115/60 kV Transformer Capacity

Projects where Mitigation is Still Required

- Mitigation has been identified as being required for the remainder of the previously approved projects.

- The ISO is continuing to review if the project scope as approved is required or potential modifications to the scope to address current required need

Next Steps

- The ISO will include in the draft 2016-2017 Transmission Plan recommendations for canceling the previously approved projects that are no longer found to be needed:
  - Currently there are 16 projects identified where mitigation is no longer required
  - All of the projects are local area 115 kV or 60 kV projects

- The ISO will include in the draft 2016-2017 Transmission Plan the assessment and recommendations for any modifications to the remaining projects where mitigation is still required to meet reliability requirements

Review of Gates-Gregg 230 kV Line Project

2012-2013 Transmission Plan

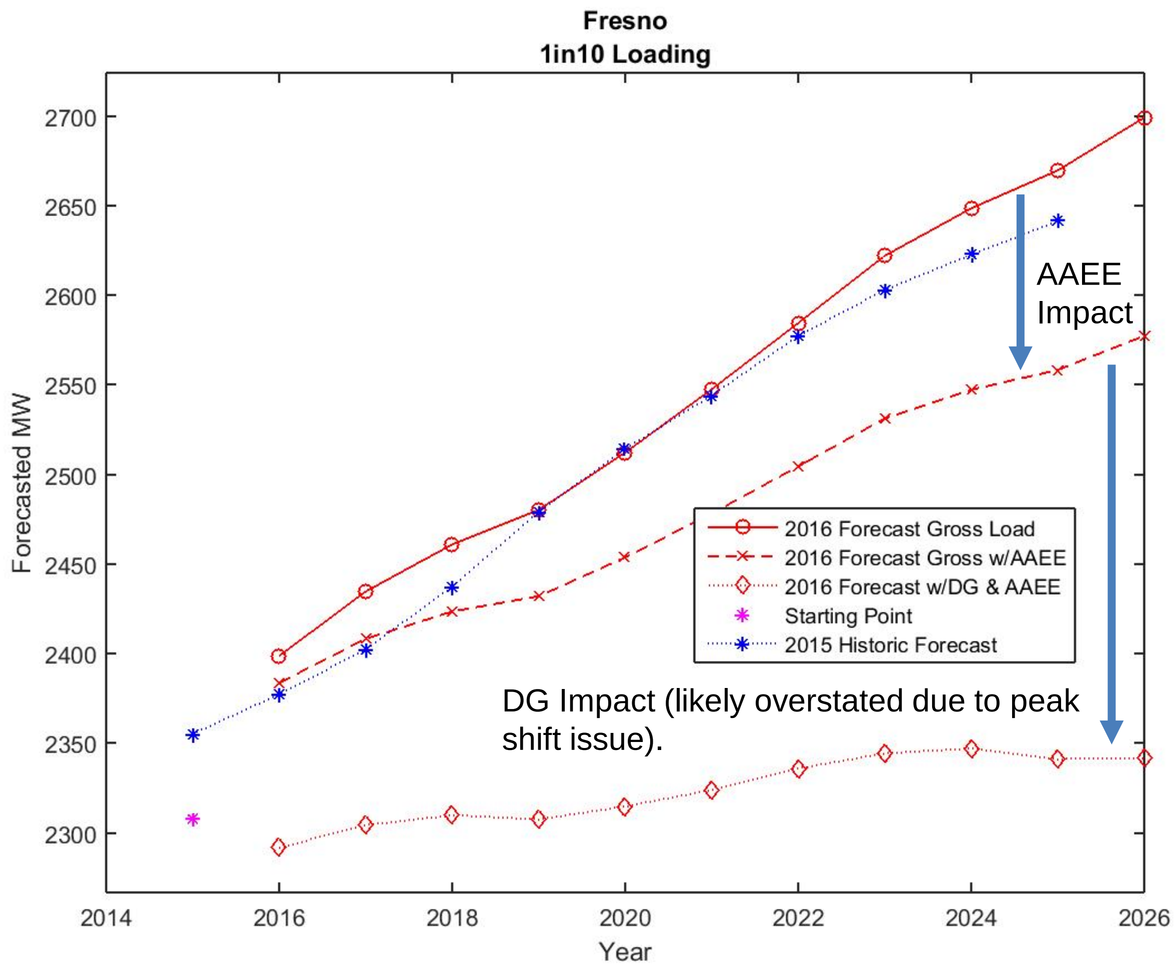
Central California Study

- The following was approved in the ISO 2012-2013 Transmission Plan to address the:
  - reliability needs of the Central California/Fresno area;
  - the pumping requirements of HELMs for area reliability; and
  - provide flexibility for the HELMs Pump Storage facility to provide ancillary services and renewable integration requirements.

Project	Estimated In-Service Date	Estimated Cost
Series Reactor on Warnerville-Wilson 230 kV Line	2017	$20-30 million
Gates #2 500/230 kV Transformer Addition	2017	$75-85 million
Kearney - Hearndon 230 kV Line Reconductoring	2017	$15-25 million
Gates-Gregg 230 kV Line	2022(1)	$115-145 million

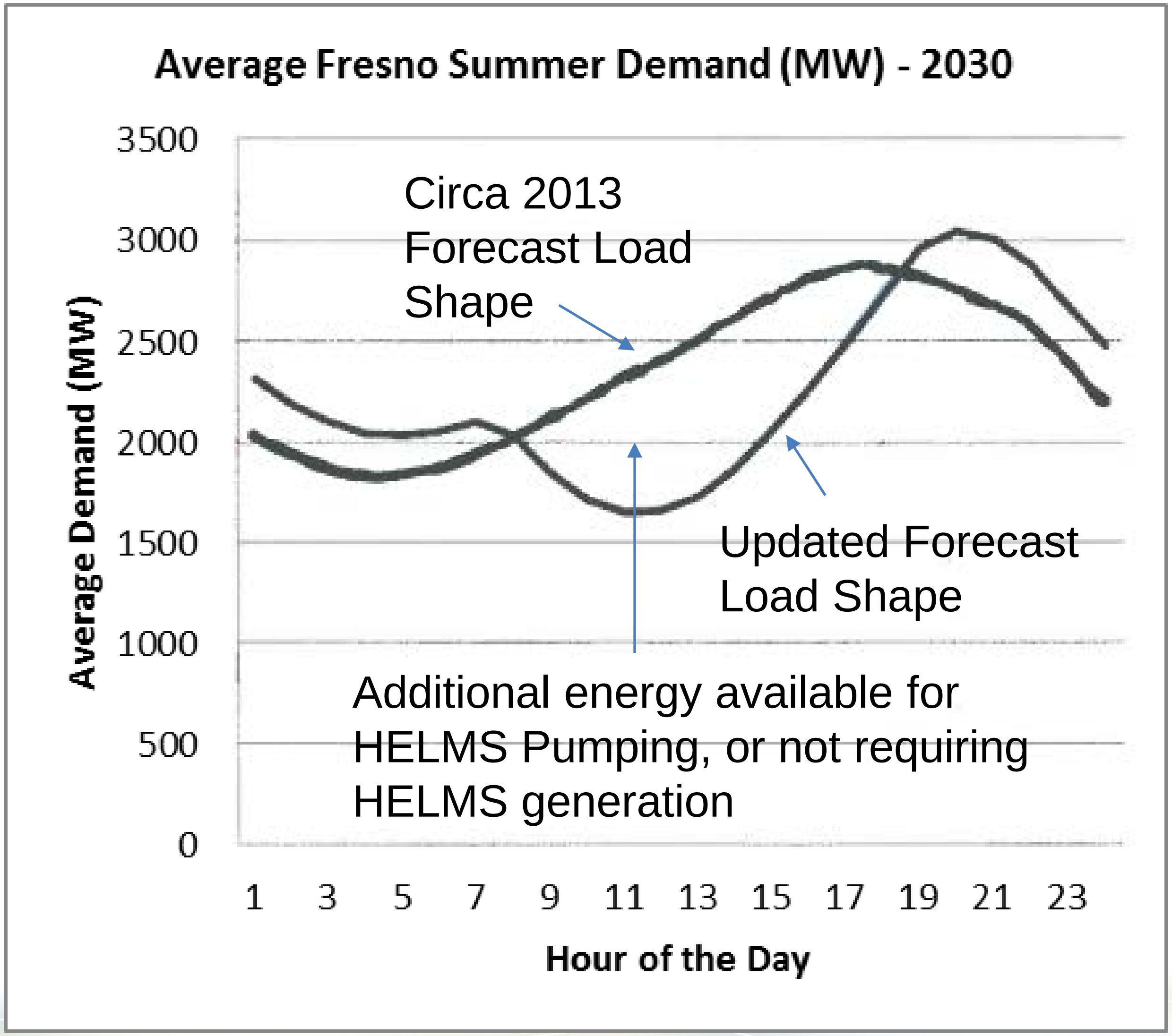
The 2015 IEPR load forecast is causing the review of a number of approved projects, as in the Fresno area:

- Reduced load forecast overall
- Reductions are likely overstated due to peak shift issues, but are still material



Impact of increased behind the meter solar generation:

- The impact is to create additional pumping opportunities, or reduce the local need for energy to be generated by HELMS



Reliability Need

- 2012-2013 Transmission Plan
  - Project was approved as a Reliability-driven project with potential renewable integration benefits
  - Reliability needs identified to start in the 2023 to 2029 timeframe

- 2016 Assessment
  - The decreased local area “energy” needs and increased pumping opportunities have pushed the reliability need out 10 years, beyond the effective planning horizon, shifting the need from *Reliability Need* to *Renewable Integration Need*

2016 Assessment of Need

- Starting case was 2017 Spring Off-Peak from the 2015-2016 TPP
- No Hydro Online in the cases
- Minimum generation to maintain adequate voltage levels
- 12 different case configurations:
  - No New Projects case
  - Case with 3 Projects
    - Gates #2 500/230 kV transformer addition;
    - Series Reactor on Warnerville-Wilson 230 kV line; and
    - Kearney-Herndon 230 kV reconductoring
  - Case with 4 Projects
    - Gates #2 500/230 kV transformer addition;
    - Series Reactor on Warnerville-Wilson 230 kV line; and
    - Kearney-Herndon 230 kV reconductoring
    - Gates-Gregg 230 kV line (which is what PG&E is filing CPCN for);
- Each case was divided into 3 Pumping scenarios
  - Single
  - Double
  - Triple

Transmission System Capability Assessment

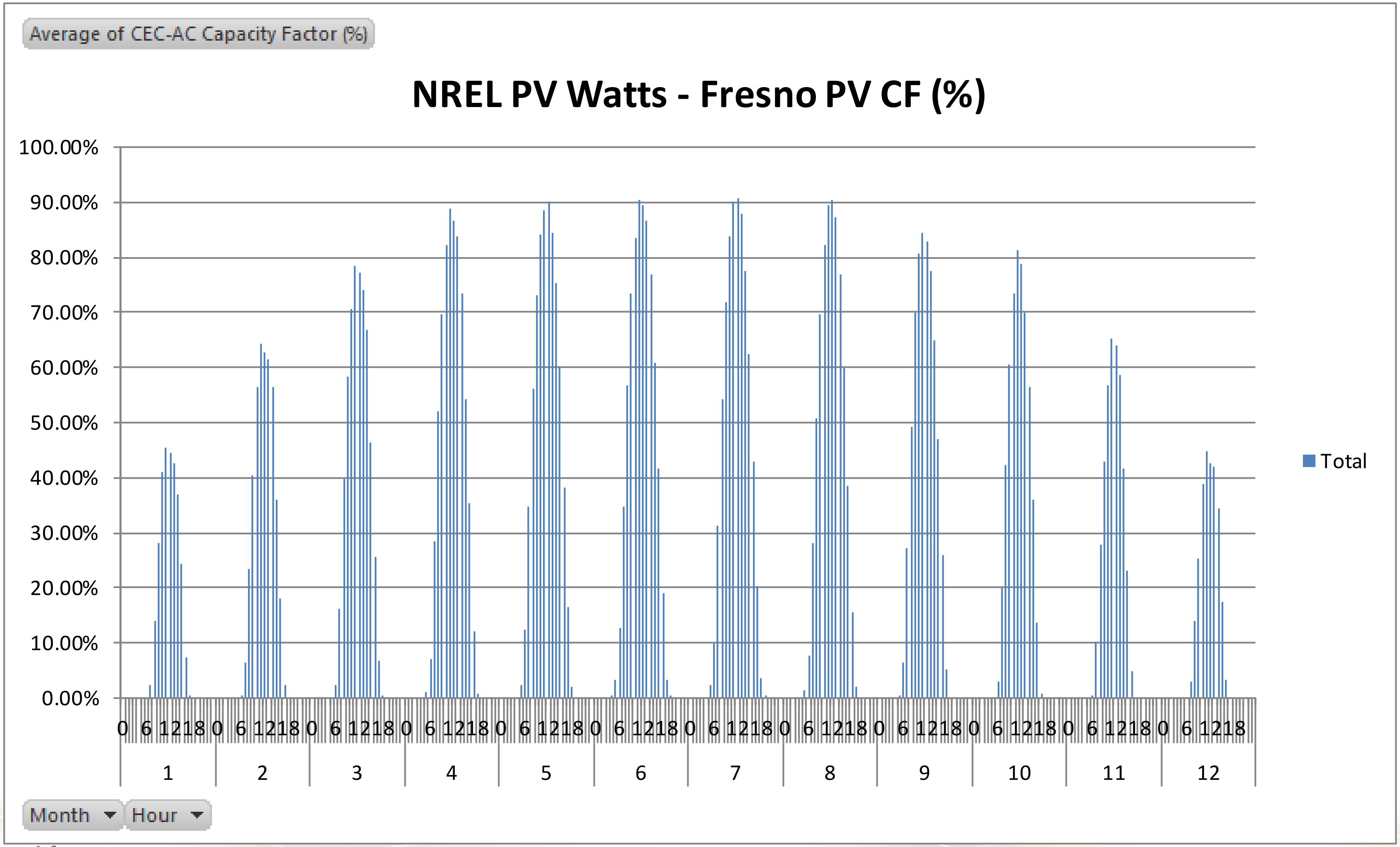
- Current System 1750 MW
- With 3 Projects 1980 MW
  - Warnerville-Wilson 230 kV series reactor
  - Gates Gregg 500/230 kV transformer addition
  - Kearney-Herndon 230 kV line reconductor
- With 4 Projects 2605 MW
  - 3 projects plus
  - Gates-Gregg 230 kV line

2016 Need Assessment
Fresno Area Current Forecast

- Started with 2015 Fresno Area hourly load data
- Increased based upon area forecast growth rate
- Reduced load based upon CEC forecast of distributed generation using Fresno PV profiles (note PG&E forecasts are higher yet for installed PV.)

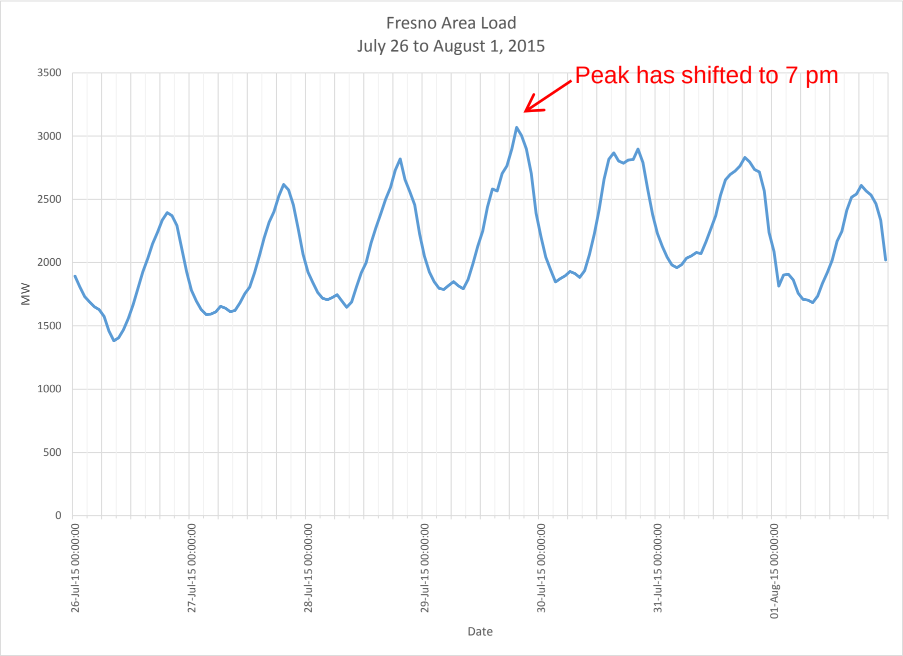
GFA CEC DG Forecast 2016 (Cumulative growth)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity	59.65	106.81	140.55	176.13	215.01	261.16	314.89	376.77	444.12	516.25	593.96

Fresno Distribution PV Capacity Factor Profiles

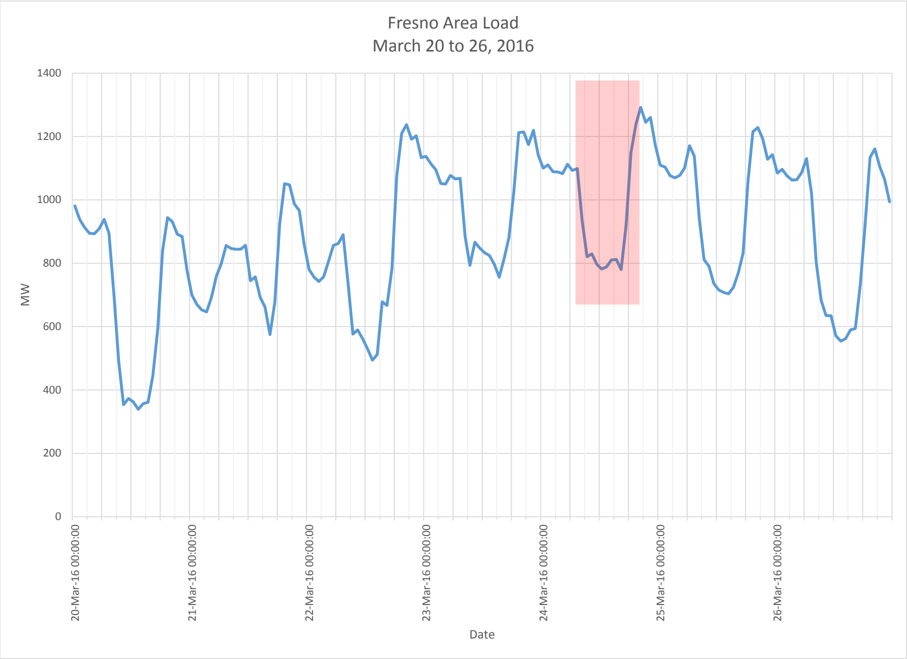


Current Fresno Load Profiles

Summer 2015

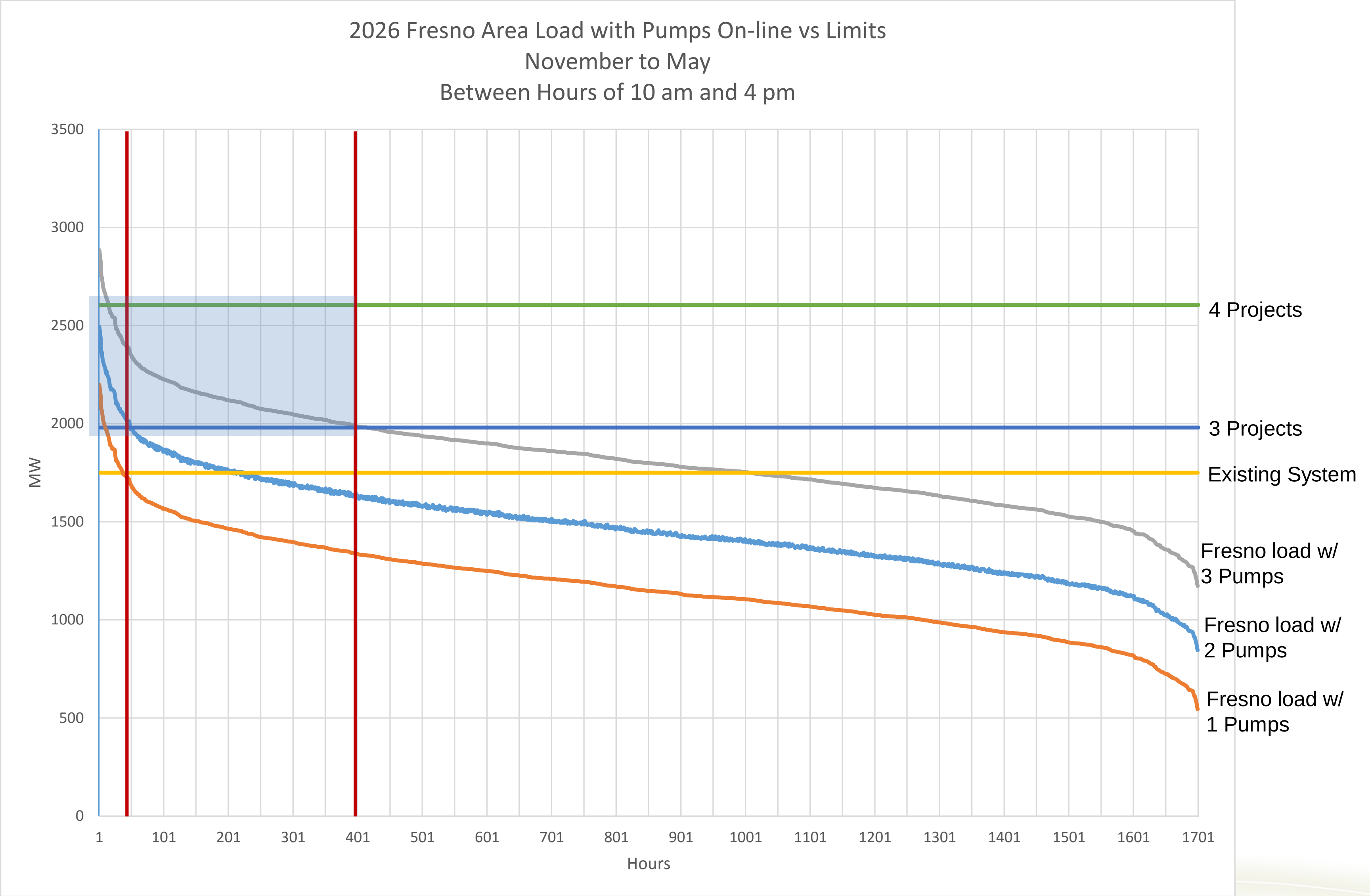


Spring 2016



2026 Area Loads with Pumps versus Capability

(Non Summer Months – when oversupply conditions are expected)



Gates-Gregg 230 kV Transmission Line
Economic Assumptions

- In-service Date – 2022
- Estimated Cost – $165 million
- Project Costs to date – $15 million
  - *As of June 15, 2016*
- Annual economic benefit to support the project would need to be in the order of $15-20 million
- System over-supply potential
  - November to May
  - 10 am to 4 pm
- Cost of curtailment from recent ISO studies
  - $40 to 66 / MWh

Value of Curtailment
November – May 10 am to 4 pm

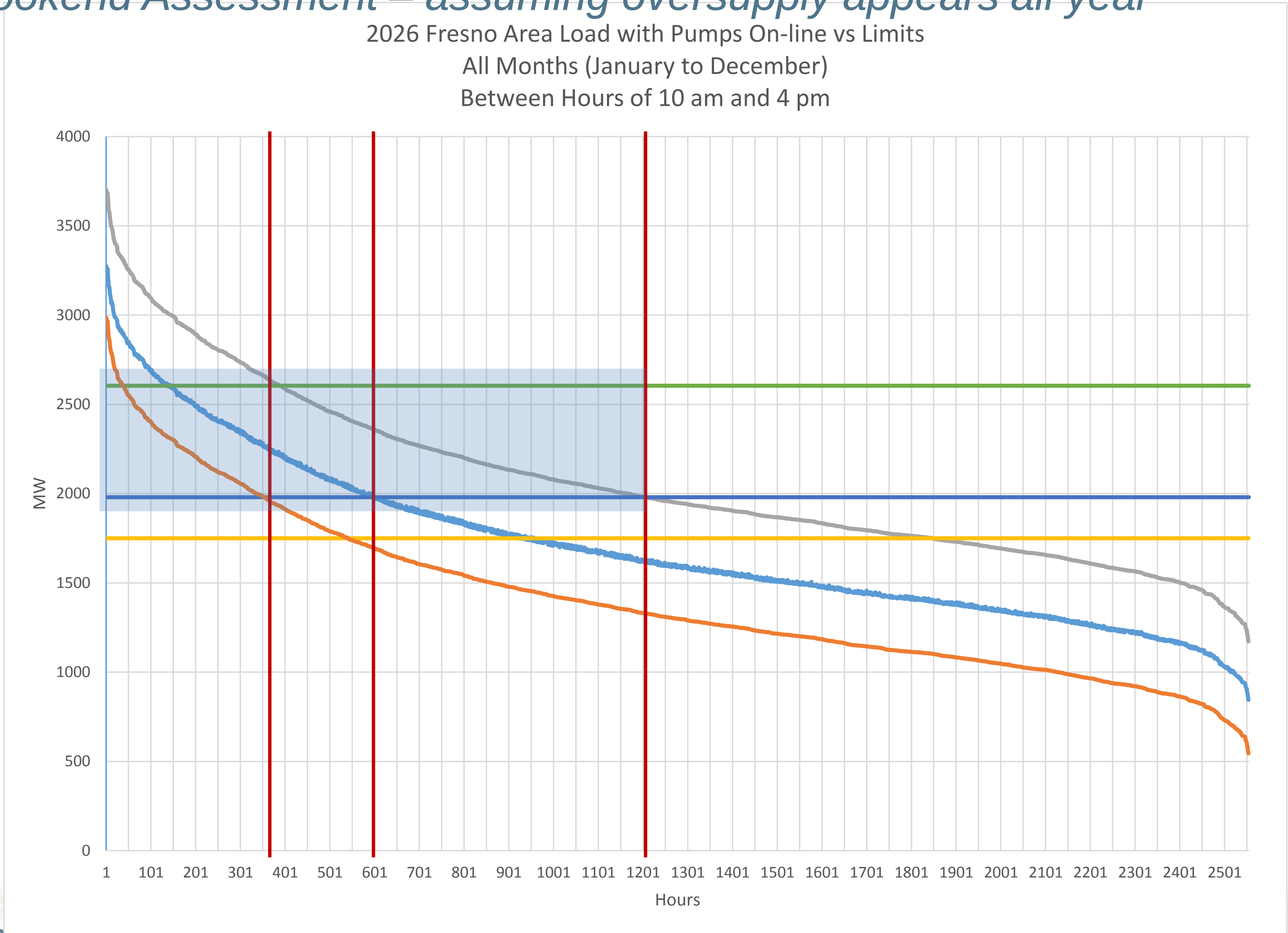
- MWh where pumping not available without Gates-Gregg 230 kV Line
  - (400 hours * 300 MW) + (50 hours * 300 MW)
  - 135,000 MWh

- Assuming system over supply for all hours pumping not available

- Value of Pumping for Avoided Curtailment
  - At $40/MWh 135,000MWh * $40/MWh = $5.4 million/year
  - At $66/MWh 135,000MWh * $66/MWh = $8.9 million/year
  - At $100/MWh 135,000MWh * $100/MWh = $13.5 million/year

2026 Area Loads with Pumps versus Capability

Bookend Assessment – assuming oversupply appears all year



Value of Curtailment – Bookend Assessment *January – December 10 am to 4 pm*

- MWh where pumping not available without Gates- Gregg 230 kV Line
  - (800 hours * 300 MW) + (450 hours * 300 MW) + (300 hours * 300 MW)
  - 465,000 MWh

- Assuming system over supply for all hours pumping not available

- Value of Pumping for Avoided
  - At $40/MWh 465,000MWh * $40/MWh = $18.6 million/year
  - At $66/MWh 465,000MWh * $66/MWh = $30.7 million/year

  - At $100/MWh 465,000MWh * $100/MWh = $46.5 million/year

Uncertainty Could Impact Need

- Load Forecast
  - Distributed PV installed capacity and output
    - Increase in PV growth rate would decrease benefit
    - Reduction in PV growth rate would increase benefit
  - Load growth
    - Higher load growth and Fresno area forecast would increase benefit
    - Lower load growth and Fresno area forecast would increase benefit
- Expanding over-supply timeframe to summer periods
  - Increase the benefits

Gates-Gregg 230 kV Transmission Line Project Next Steps

- There does not appear to be sufficient economic benefits to support the Gates-Gregg 230 kV Transmission Line Project
- The ISO is considering cancelling the Gates-Gregg 230 kV Transmission Line Project in the ISO 2016-2017 transmission planning process
  - The ISO may consider deferring the cancelation and putting the project on hold to further assess the uncertainties where the project may have sufficient economic benefits

Next Steps

Kim Perez
Stakeholder Engagement and Policy Specialist

2016-2017 Transmission Planning Process Stakeholder Meeting
November 16, 2016

2016-2017 Transmission Planning Process
Next Steps

- Comments due November 30, 2016
  - regionaltransmission@caiso.com
- Draft Transmission Plan posted January 31, 2017
- Stakeholder Meeting middle of February 2017