Agenda

Draft 2013-2014 ISO Transmission Plan Stakeholder Meeting

Tom Cuccia
Sr. Stakeholder Engagement and Policy Specialist
February 12, 2014

2013-2014 Draft Transmission Plan Stakeholder Meeting - Today's Agenda

Topic	Presenter
Opening	Tom Cuccia
Introduction & Overview	Neil Millar
Recommended Reliability Projects for Kern area and Greater Bay Area	Joe Meier and Bryan Fong
San Francisco Peninsula – Extreme Event Assessment	Jeff Billinton
Southern California (LA Basin/San Diego) Recommendations	David Le
Preferred Resource Analysis Results	Robert Sparks and David Le
Recommended Reliability Projects for San Diego area	Frank Chen
Recommended Policy-Driven Projects	Songzhe Zhu
Economic Planning Study Final Recommendations	Binaya Shrestha and Luba Kravchuk
Transmission Program Impact on HV TAC and Eligibility of Competitive Solicitation	Neil Millar
Wrap-up and Next Steps	Tom Cuccia

Introduction & Overview
Transmission Plan Development

Draft 2013-2014 ISO Transmission Plan Stakeholder Meeting

Neil Millar
Executive Director - Infrastructure Development
February 12, 2014

2013-2014 Transmission Planning Cycle

April 2013 — **March 2014** — **October 2014**

Coordination of Conceptual Statewide Plan

ISO Board Approval of Transmission Plan

Phase 1

Development of ISO unified planning assumptions and study plan

- Incorporates State and Federal policy requirements and directives
- Demand forecasts, energy efficiency, demand response
- Renewable and conventional generation additions and retirements
- Input from stakeholders
- Ongoing stakeholder meetings

Phase 2

Technical Studies and Board Approval

- Reliability analysis
- Renewable delivery analysis
- Economic analysis
- Central California Study
- Publish comprehensive transmission plan
- ISO Board approval

Phase 3

Receive proposals to build identified reliability, policy and economic transmission projects.

Continued regional and sub-regional coordination

Development of 2013-2014 Annual Transmission Plan

Reliability Analysis ☑
(NERC Compliance)

33% RPS Portfolio Analysis ☑
- Incorporate GIP network upgrades
- Identify policy transmission needs

Economic Analysis ☑
- Congestion studies
- Identify economic transmission needs

Other Analysis☑
(LCR, SPS, etc.)

Results

Summary of Needed Reliability Driven Transmission Projects

Service Territory	Number of Projects	Cost
Pacific Gas & Electric (PG&E)	15 *	$536.4
Southern California Edison Co. (SCE)	2	$712.0
San Diego Gas & Electric Co. (SDG&E)	11	$584.0
Valley Electric Association (VEA)	1	0.1
Total	29	$1,832.5

* The ISO is undertaking further analysis regarding the San Francisco Peninsula this year and may bring forward a recommendation for ISO Board approval as an addendum to this plan or in the next planning cycle as part of the 2014-15 Transmission Plan.

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Policy and Economic driven solutions:

- Two Category 1 policy driven solutions have been identified:
  – a 300 Mvar SVC at Suncrest, and
  – a Lugo-Mohave series capacitor and related terminal upgrades

- One economically driven element has been identified*:
  – Delaney-Colorado River 500 kV transmission line

* The ISO intends to complete further analysis on the Harry Allen-Eldorado potential economically driven facility and bring the project forward for consideration at a future Board of Governors meeting.

Eligibility for competitive solicitation:

- Reliability-driven:
  - Imperial Valley flow controller
  - Estrella 230/70 kV substation*
  - Wheeler Ridge Junction 230/70 kV substation*
- Policy-driven:
  - Suncrest 300 Mvar SVC
- Economically driven:
  - Delaney-Colorado River 500 kV transmission line

* Only the 230 kV facilities including the 230/70 kV transformers are eligible for competitive solicitation; the 70 kV facilities are not.

Management approval has been received on 17 projects less than $50 million

- These projects were reviewed individually at the November 21 stakeholder meeting, and approval took place after the December 18 Board of Governors meeting.
- They will not be reviewed and discussed in today's stakeholder session.
- 5 remaining projects less than $50 million will be reviewed as part of today's session, with the projects greater than $50 million.

No.	Project Name
1	Mission Bank #51 and #52 replacement
2	Rose Canyon-La Jolia 69 kV T/L
3	TL690A/TL690E, San Luis Rey-Oceanside Tap and Stuart Tap-Las Pulgas 69 kV sections re-conducto
4	TL13834 Trabuco-Capistrano 138 kV Line Upgrade
5	Victor Loop-in
6	CT Upgrade at Mead-Pahrump 230 kV Terminal
7	Estrella Substation Project
8	Glenn 230/60 kV Transformer No. 1 Replacement
9	Kearney-Kerman 70 kV Line Reconductor
10	Laytonville 60 kV Circuit Breaker Installation Project
11	McCall-Reedley #2 115 kV Line
12	Mosher Transmission Project
13	Reedley 115/70 kV Transformer Capacity Increase
14	San Bernard – Tejon 70 kV Line Reconductor
15	Taft-Maricopa 70 kV Line Reconductor
16	Weber-French Camp 60 kV Line Reconfiguration
17	Wheeler Ridge-Weedpatch 70 kV Line Reconductor

2013-2014 Transmission Plan – Initial Comments

- Continued focus on managing CEII access:
  - San Francisco peninsula analysis
  - Detailed discussions
- Submissions into request windows that were not found to be needed

Reliability Projects Recommended for Approval
Kern Area

2013-2014 Transmission Plan Stakeholder Meeting

Joseph E Meier, P.E.
Sr. Regional Transmission Engineer
February 12, 2014

Two Projects Recommended for Approval (over $50M)

Midway-Kern PP #2 230kV Line

Need: NERC Category C and California ISO Planning Standards Planning for New Transmission vs. Involuntary Load Interruption Standard (Section VI - 2 All single substations >100MW should be looped).

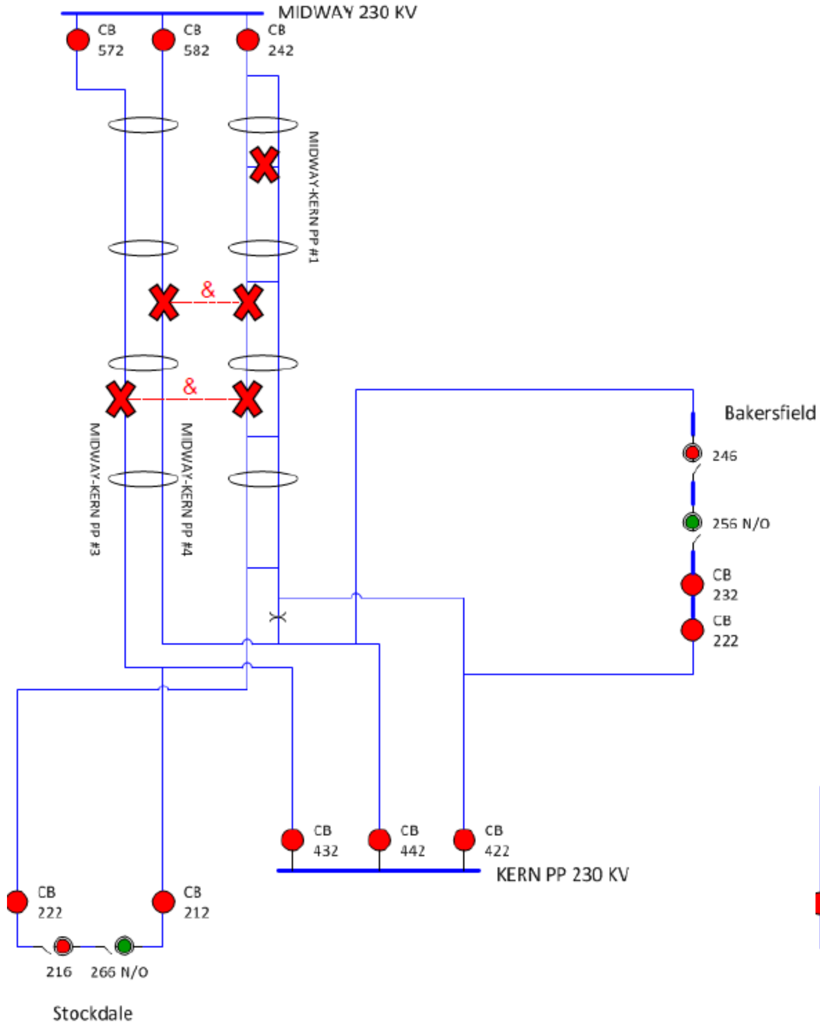
Project Scope: Unbundle and reconductor the Midway-Kern PP #1 230kV line, loop Bakersfield on the #1 or #2 line and move Stockdale taps into Kern PP 230kV substation, one bay at Midway 230kV and three bays at Kern PP 230kV

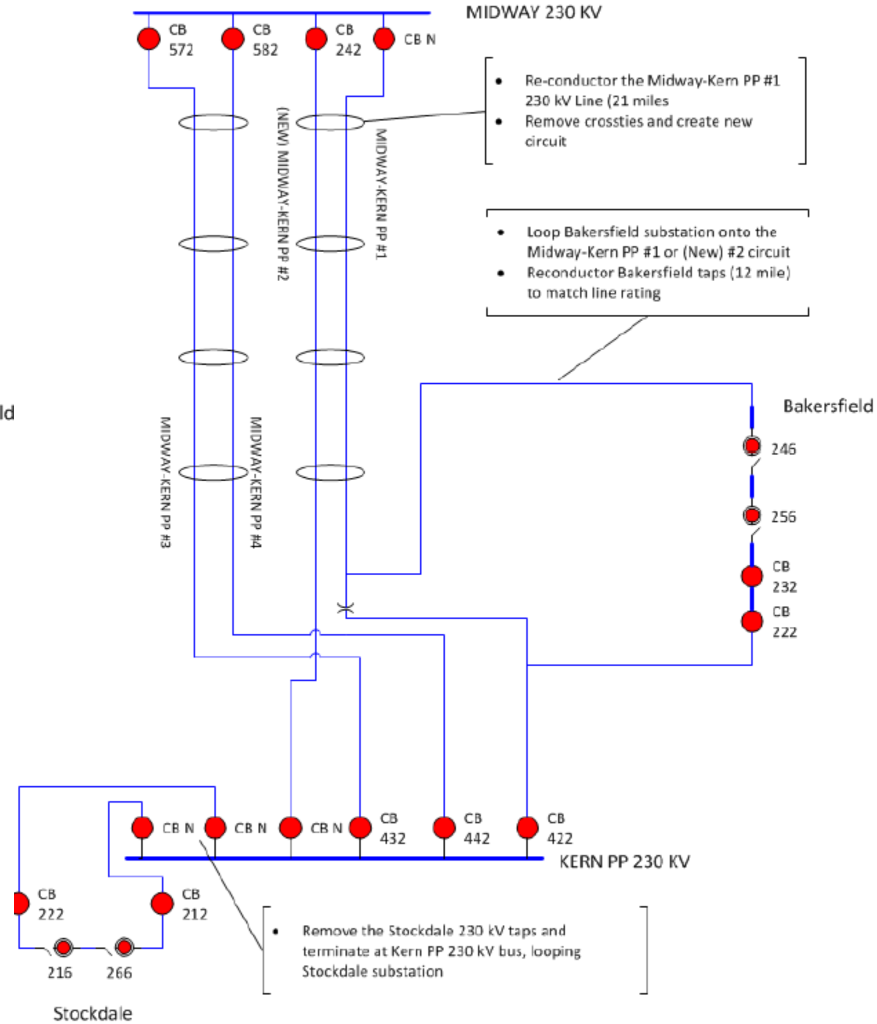
Cost: $60M-$90M

Other Considered Alternatives
- Status Quo
- New Midway -Kern PP 230 kV Line (new ROW)

Expected In-Service: May 2019

Midway-Kern PP #2 230kV Line





Wheeler Ridge Junction Station

Need: Reliability – NERC Category B, C & Joint Ownership Obligations with CDWR

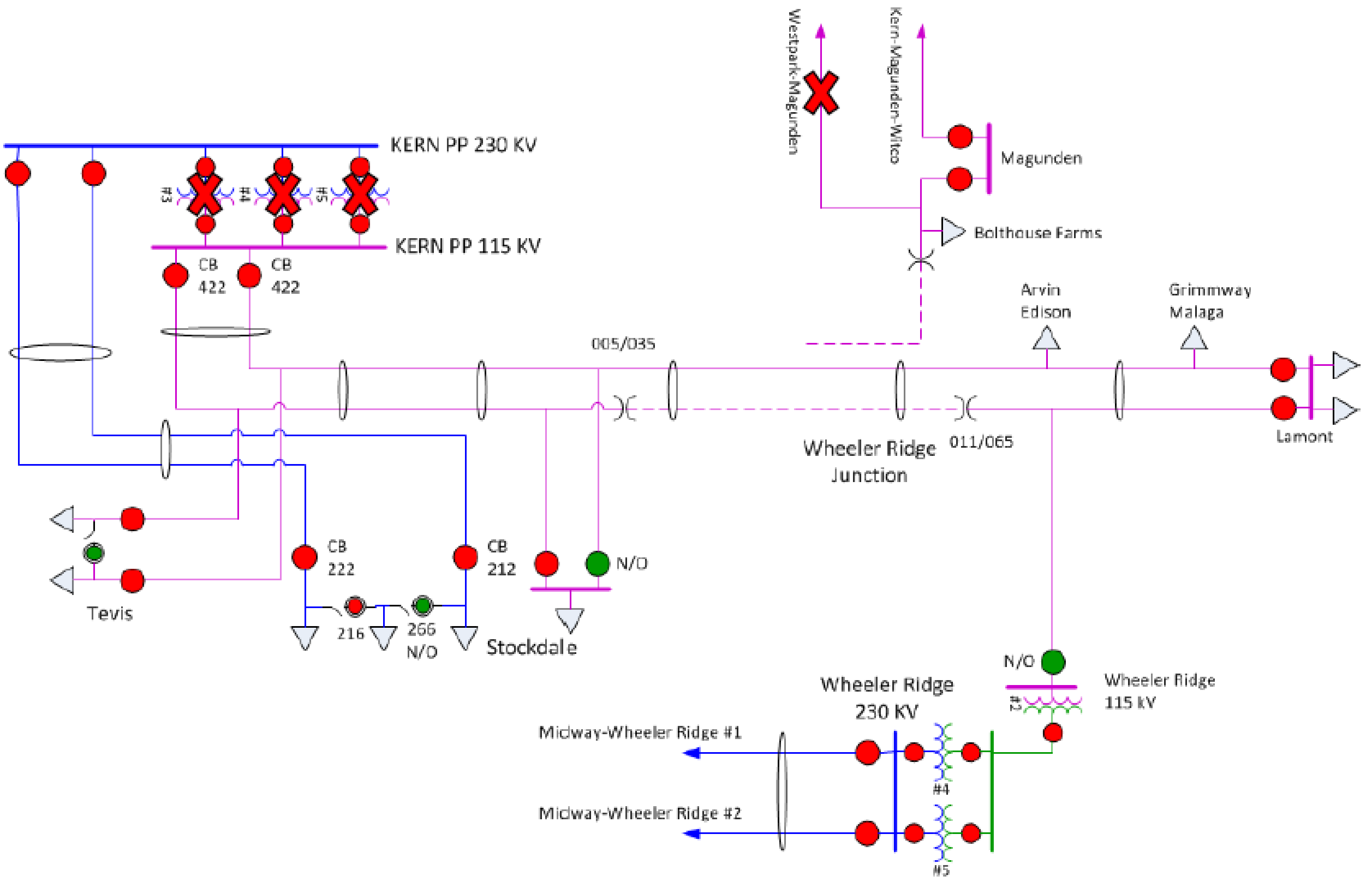
Project Scope: Build new substation between Kern PP 230kV and Wheeler Ridge 230kV. Convert Wheeler Ridge-Lamont 115kV to 230kV operation and terminate at WRJ.

Cost: $90M-$140M

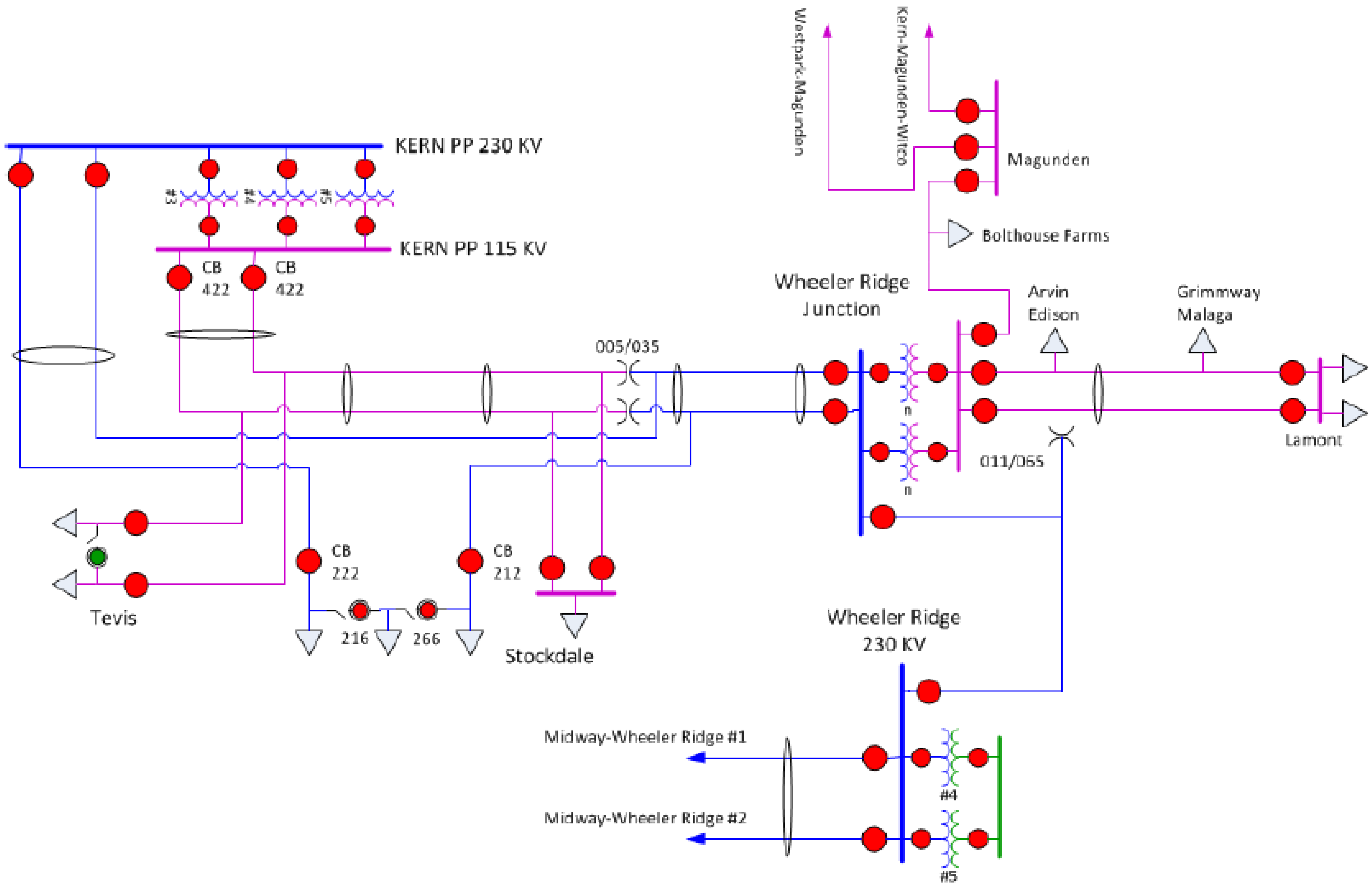
Other Considered Alternatives
- Status Quo
- New Midway –Wheeler Ridge 230 kV capacity increase

Expected In-Service: May 2020

Wheeler Ridge Junction Station



Wheeler Ridge Junction Station



Reliability Projects Recommended for Approval
Greater Bay Area

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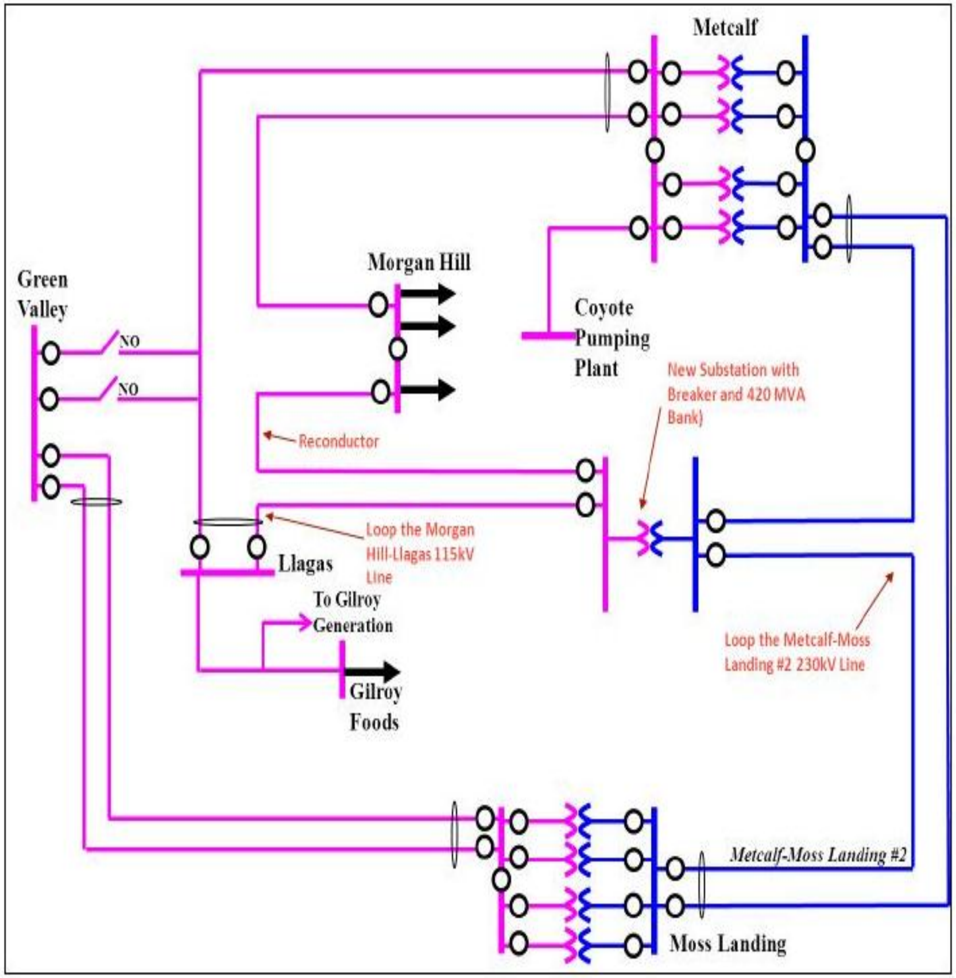
Bryan Fong
Sr. Regional Transmission Engineer
February 12, 2014

One (1) Project Recommended for Approval (under $50 Million)

Morgan Hill Area Reinforcement



<u>Need:</u> Consequential Load Drop (~170MW) & Gen Drop (~240MW) under Category C/ LCR Reduction

<u>Project Scope:</u> Construct a new 230/115 kV substation, Spring Substation, west of the existing Morgan Hill Substation. Install a new 230/115 kV 420 MVA transformer at Spring Substation. Loop the existing Morgan Hill-Llagas 115 kV Line into Spring 115 kV bus using a portion of the idle Green Valley-Llagas 115 kV Line Right-of-Way. Reconductor the Spring-Llagas 115 kV Line with bundled 715 Al or similar. Loop the Metcalf-Moss Landing No.2 230 kV Line into the Spring Substation 230 kV bus

<u>Cost:</u> $35-45M

<u>Other Considered Alternatives:</u>
Status Quo

<u>Expected In-Service</u>: 2021

<u>Interim Plan:</u> Action Plan

San Francisco Peninsula – Extreme Event Assessment

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Jeff Billinton
Manager, Regional Transmission - North
February 12, 2014

Please Note: This presentation can be found on the Market Participant Portal.

Southern California Reliability Assessment (LA Basin and San Diego)

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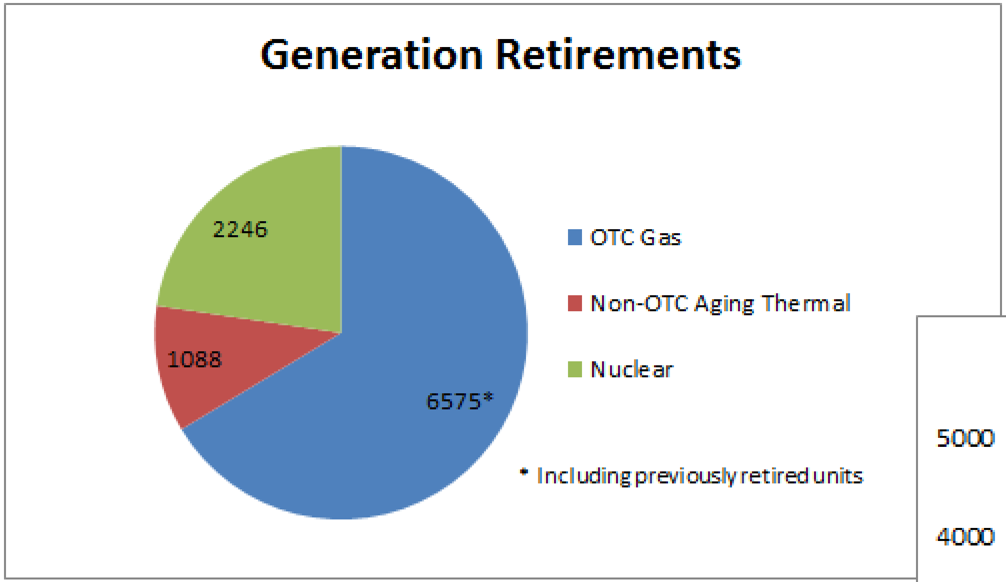
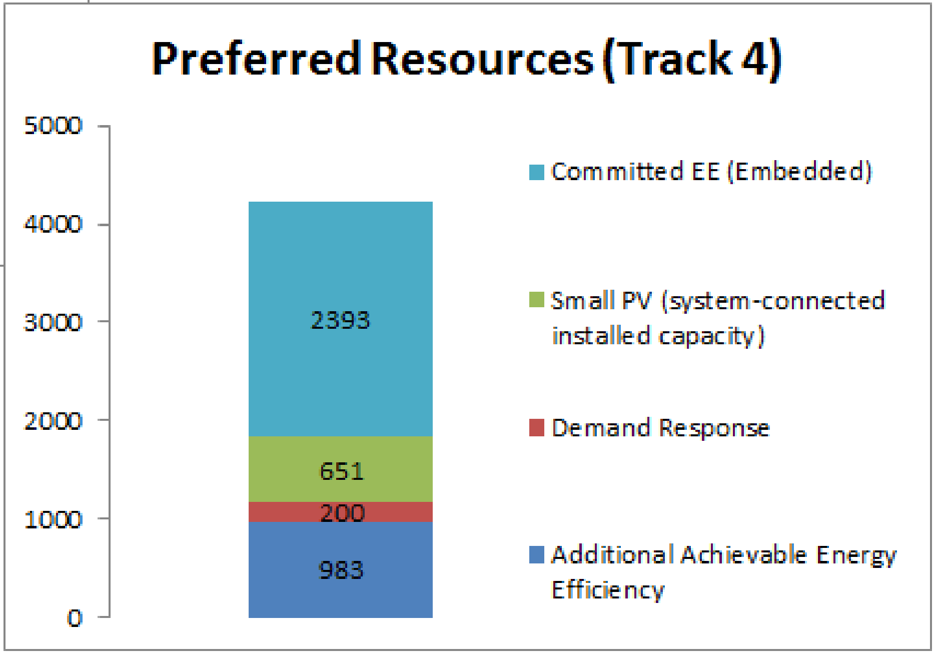
David Le
Senior Advisor Regional Transmission Engineer
February 12, 2014

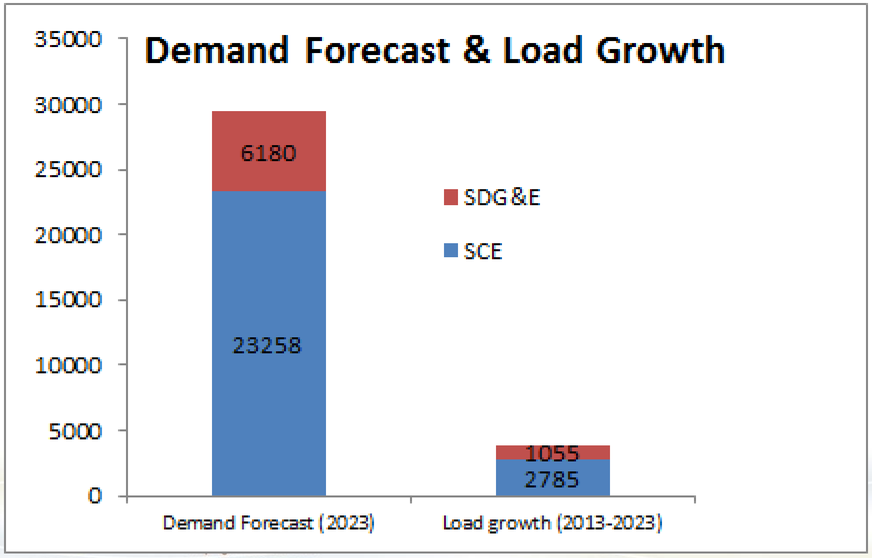
The ISO transmission plan for the LA Basin and San Diego area:

- Generally aligns with the "Preliminary Reliability Plan for LA Basin and San Diego" and is based on the premise that an array of resources will play a role in meeting the overall area needs:
  - Preferred resources (EE, DR, renewables, CHP) and storage
  - Transmission upgrades
  - Conventional generation
- Is based generally on the following assumptions:
  - The ISO Board-approved transmission upgrades,
  - The CPUC Decisions from LTPP Track 1, and
  - The study assumptions from the CPUC Track 4 Scoping Memo
- Is an iterative step in the coordination of the overall area needs with other agency processes, including the CPUC LTPP proceedings and the CEC IEPR processes.

Study Assumptions



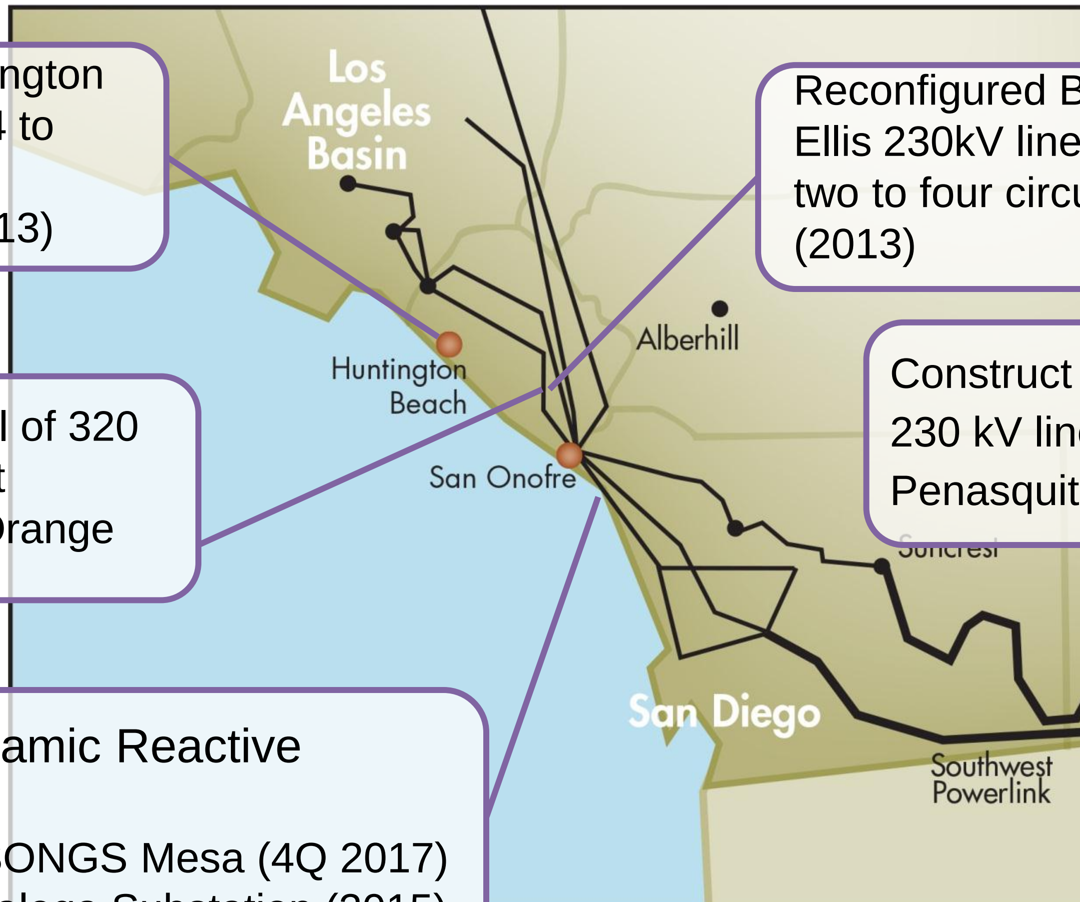




Completed Transmission Upgrades and Future Projects Approved by the ISO Board of Governors

Converted Huntington Beach Units 3&4 to Synchronous Condensers (2013)

Reconfigured Barre-Ellis 230kV lines from two to four circuits (2013)



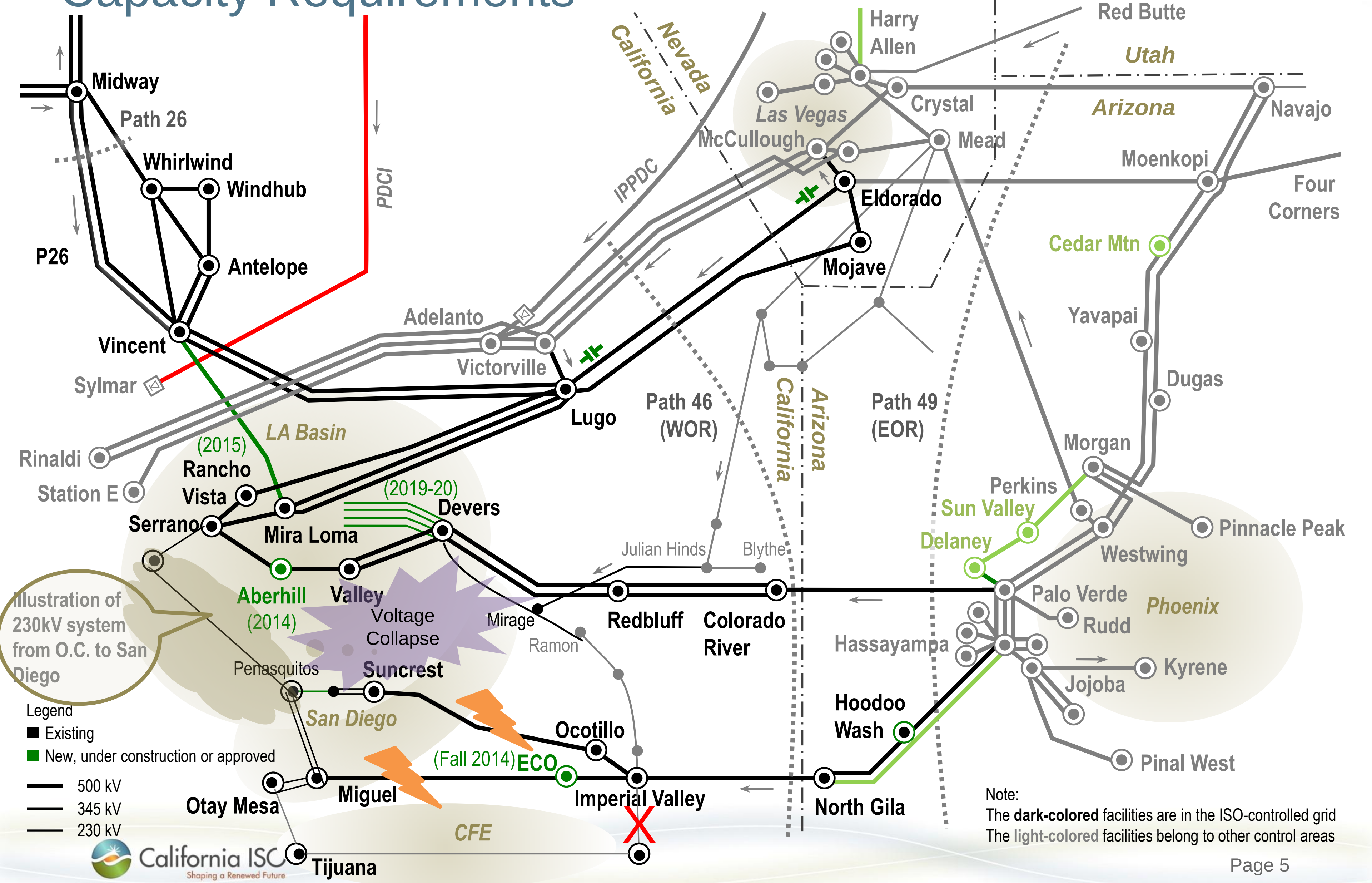
Construct an 11-mile 230 kV line from Sycamore to Penasquitos (2017)

Installed a total of 320 MVAR of shunt capacitors in Orange County (2013)

930 MVAR Dynamic Reactive Support

- 480 MVAR at SONGS Mesa (4Q 2017)
- 450 MVAR at Talega Substation (2015)

Critical Contingency that Affects the Study Area Local Capacity Requirements



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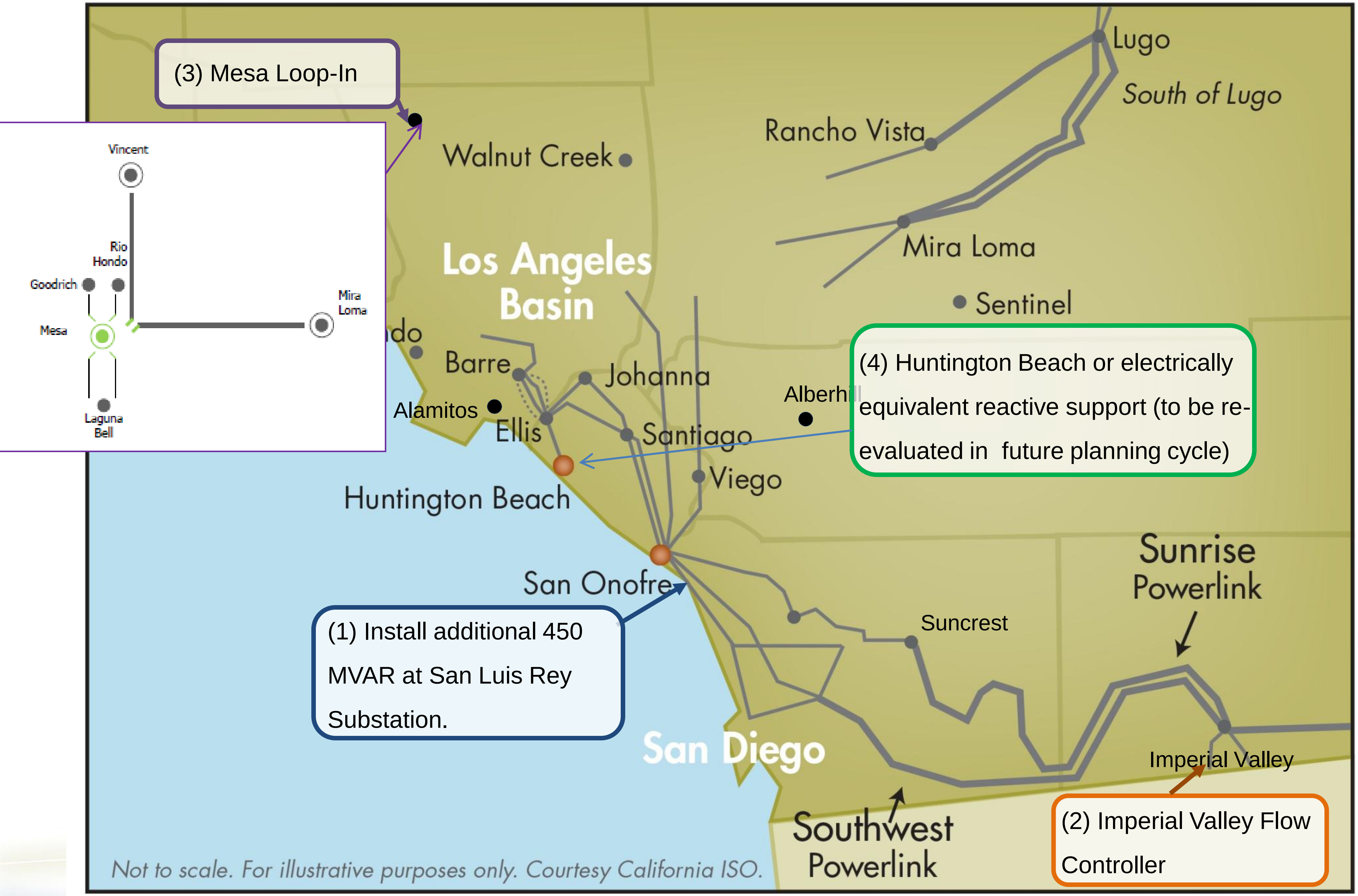
Identified Reliability Concerns

	Impacted Facilities	Contingency	Identified Concerns	Proposed Mitigation
1	LA Basin and San Diego area	ECO-Miguel 500kV, followed by Ocotillo-Suncrest 500kV (Category C3)	Voltage instability	Install dynamic reactive support at or near San Onofre switchyard, and install flow controller at or near Imperial Valley
2	Otay Mesa – Tijuana 230kV line	Same as above	Overloads	Install flow controller at or near Imperial Valley Substation
3	Ellis – Johanna, or Ellis – Santiago 230kV line	Imperial Valley – N. Gila 500kV, followed by Ellis-Santiago 230kV line (or Ellis-Johanna 230kV line)	Overloads	To be re-evaluated in 2014/2015 TPP pending the CPUC Track 4 LTPP Decisions
4	Miguel 500kV bus	Normal conditions	Low voltage: 499kV (2018) 487kV (2023)	Please see mitigation under San Diego Local Area presentation

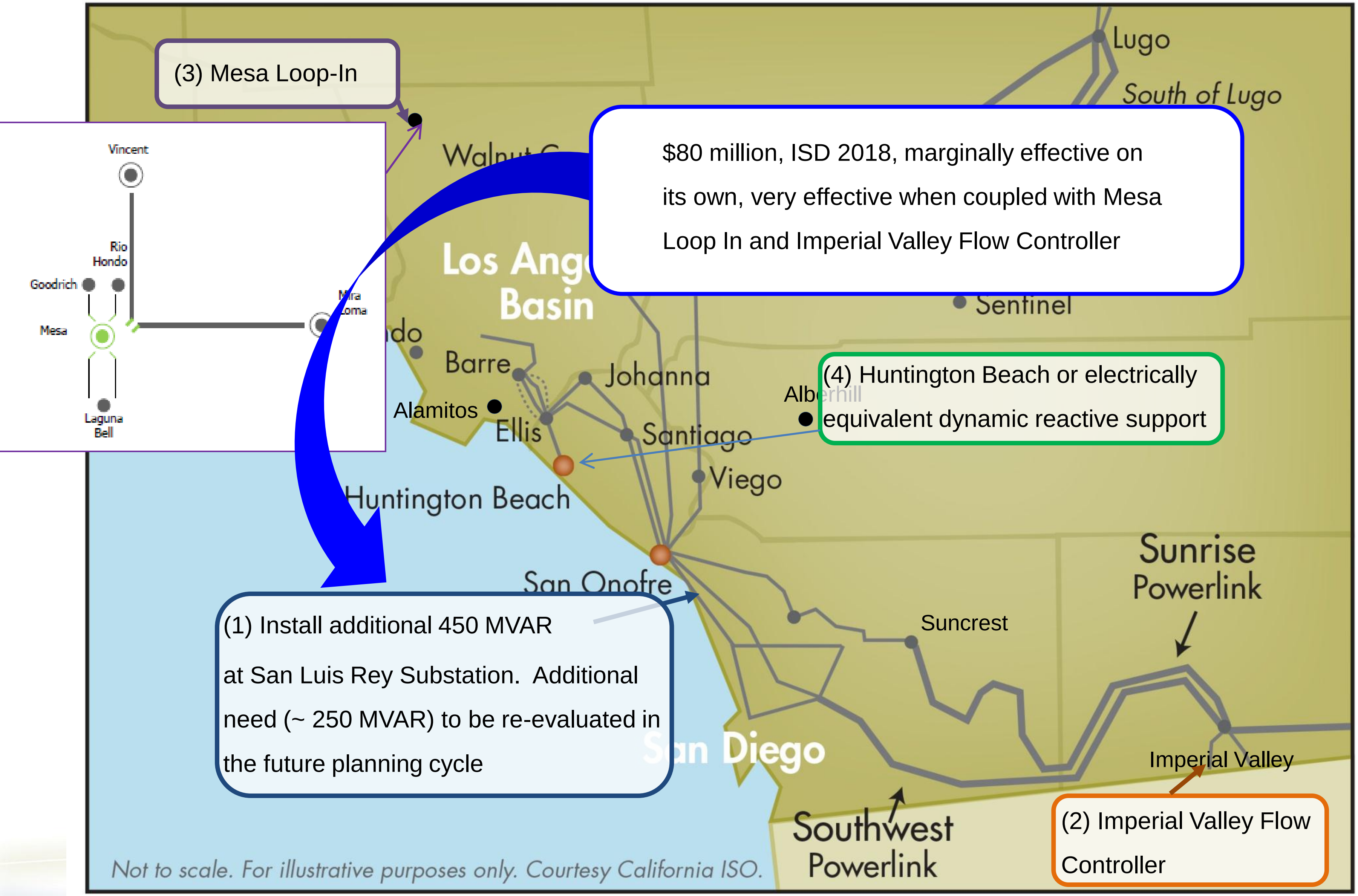
System analysis focused on a range of options and alternatives:

- Transmission options were studied assuming modest conventional generation development and
  - Group I - Transmission upgrades optimizing use of existing transmission lines
  - Group II - Transmission lines strengthening LA/San Diego connection – optimizing use of corridors into the combined area.
  - Group III - New transmission into the greater LA Basin/San Diego area.
- Effectiveness of various local preferred resource blends
- Exclusively local conventional generation - for comparative purposes

Group I: Transmission Upgrades Optimizing Use of Existing Transmission Lines



Group I: Transmission Upgrades Optimizing Use of Existing Transmission Lines – Additional SONGS reactive support

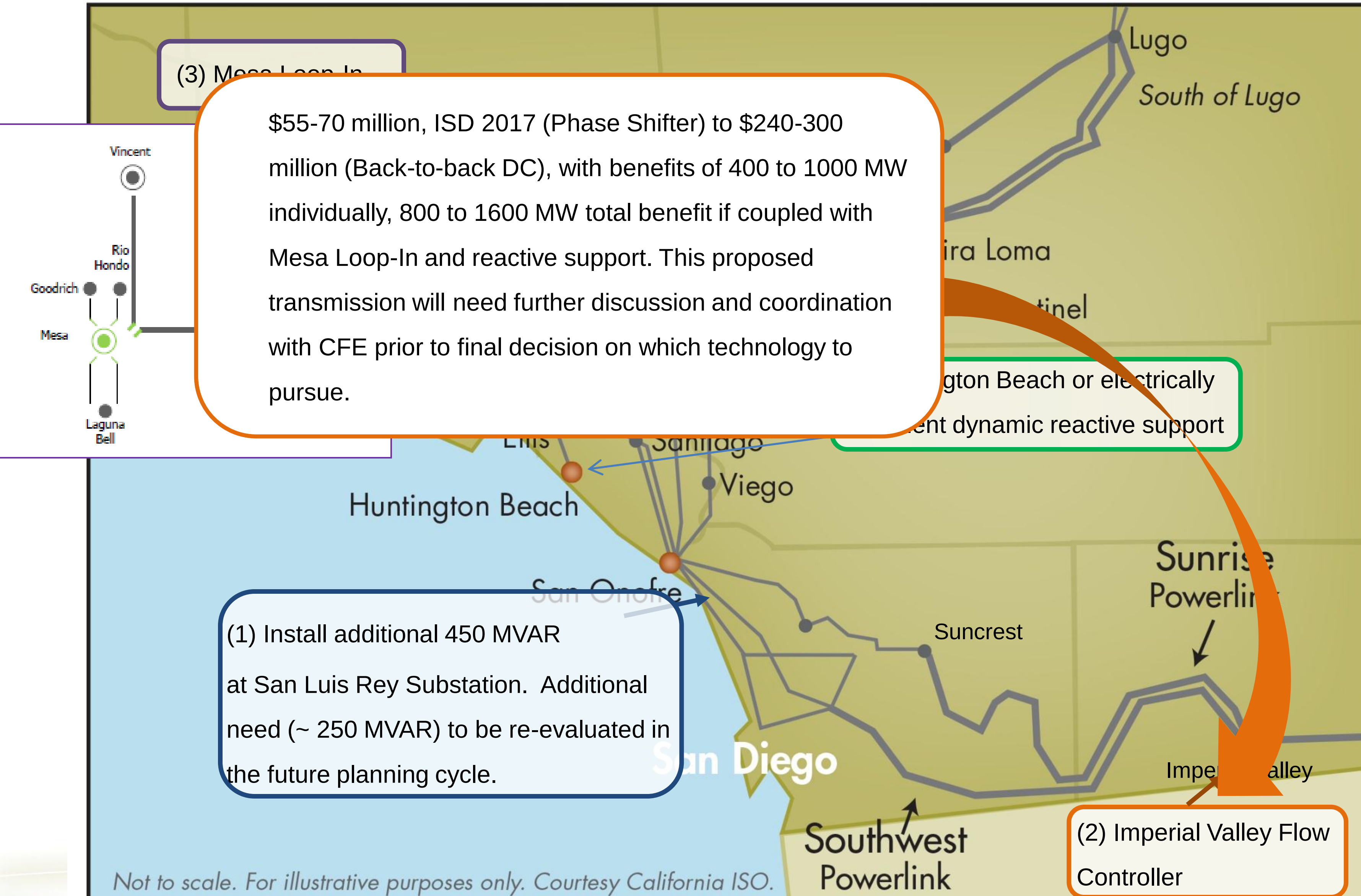


Group I: Transmission Upgrades Optimizing Use of Existing Transmission Lines – Imperial Valley to CFE Flow Control (cont'd)

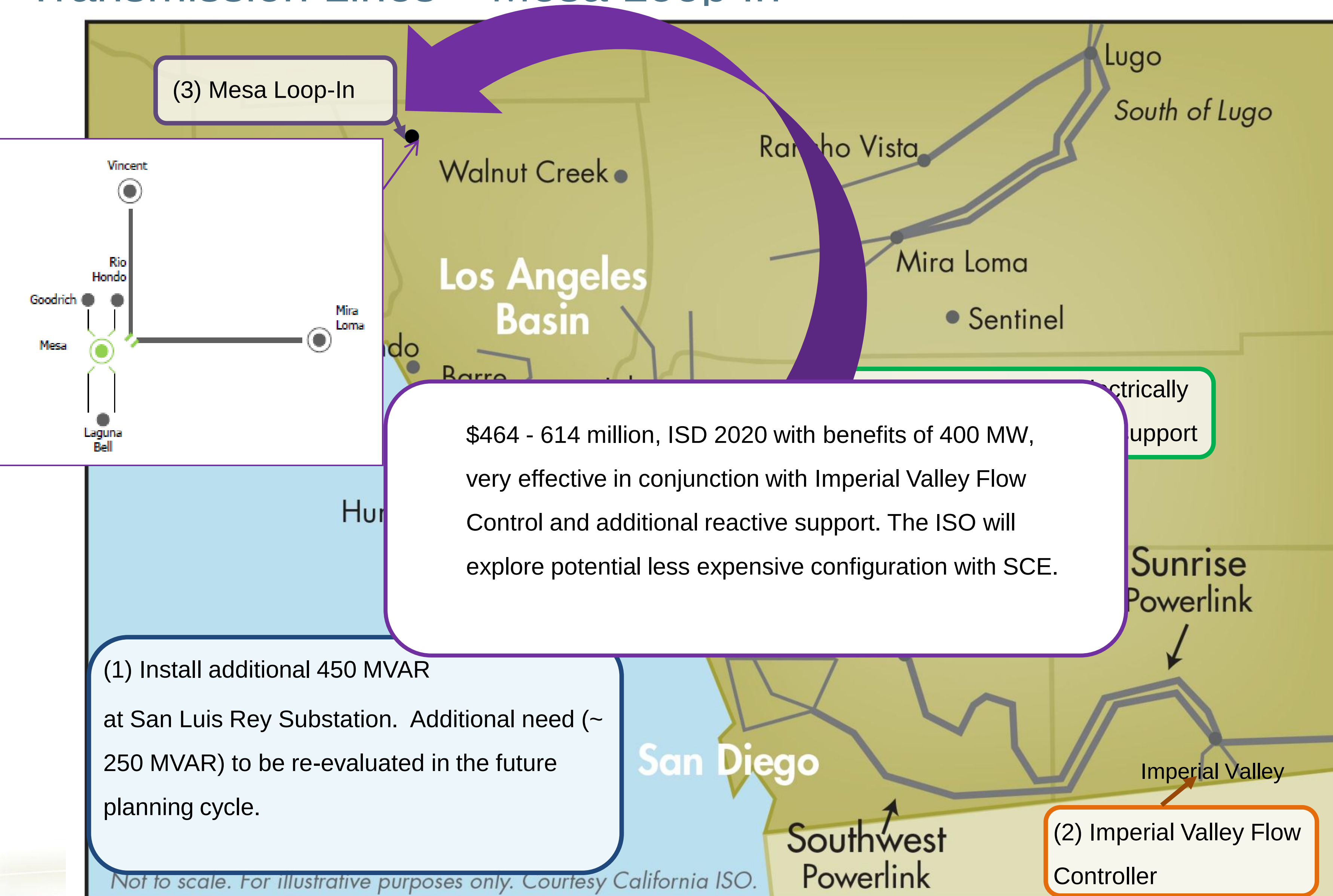
$55-70 million, ISD 2017 (Phase Shifter) to $240-300 million (Back-to-back DC), with benefits of 400 to 1000 MW individually, 800 to 1600 MW total benefit if coupled with Mesa Loop-In and reactive support. This proposed transmission will need further discussion and coordination with CFE prior to final decision on which technology to pursue.

(1) Install additional 450 MVAR at San Luis Rey Substation. Additional need (~ 250 MVAR) to be re-evaluated in the future planning cycle.

(2) Imperial Valley Flow Controller



Group I: Transmission Upgrades Optimizing Use of Existing Transmission Lines – Mesa Loop In



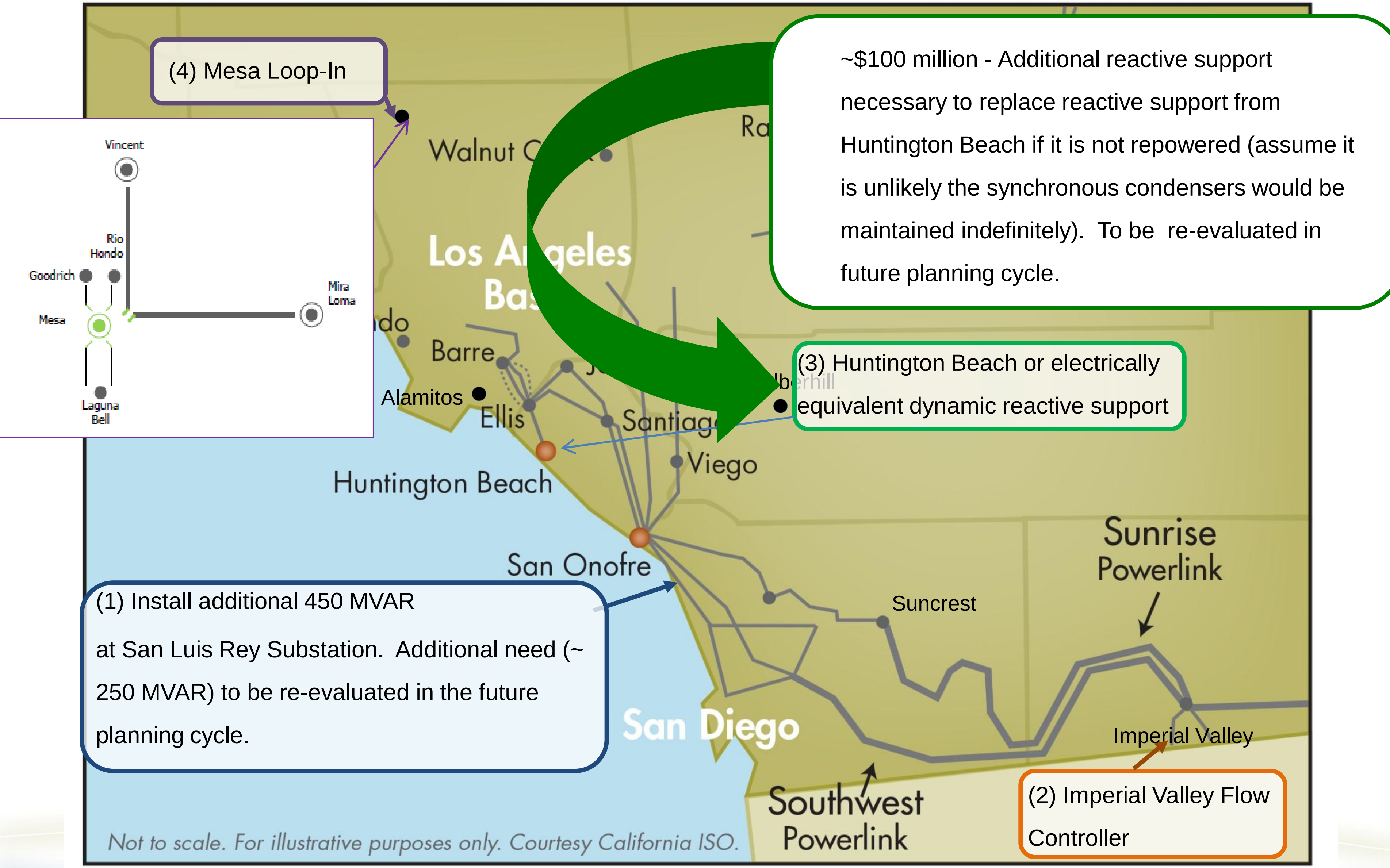
(3) Mesa Loop-In

$464 - 614 million, ISD 2020 with benefits of 400 MW, very effective in conjunction with Imperial Valley Flow Control and additional reactive support. The ISO will explore potential less expensive configuration with SCE.

(1) Install additional 450 MVAR at San Luis Rey Substation. Additional need (~ 250 MVAR) to be re-evaluated in the future planning cycle.

(2) Imperial Valley Flow Controller

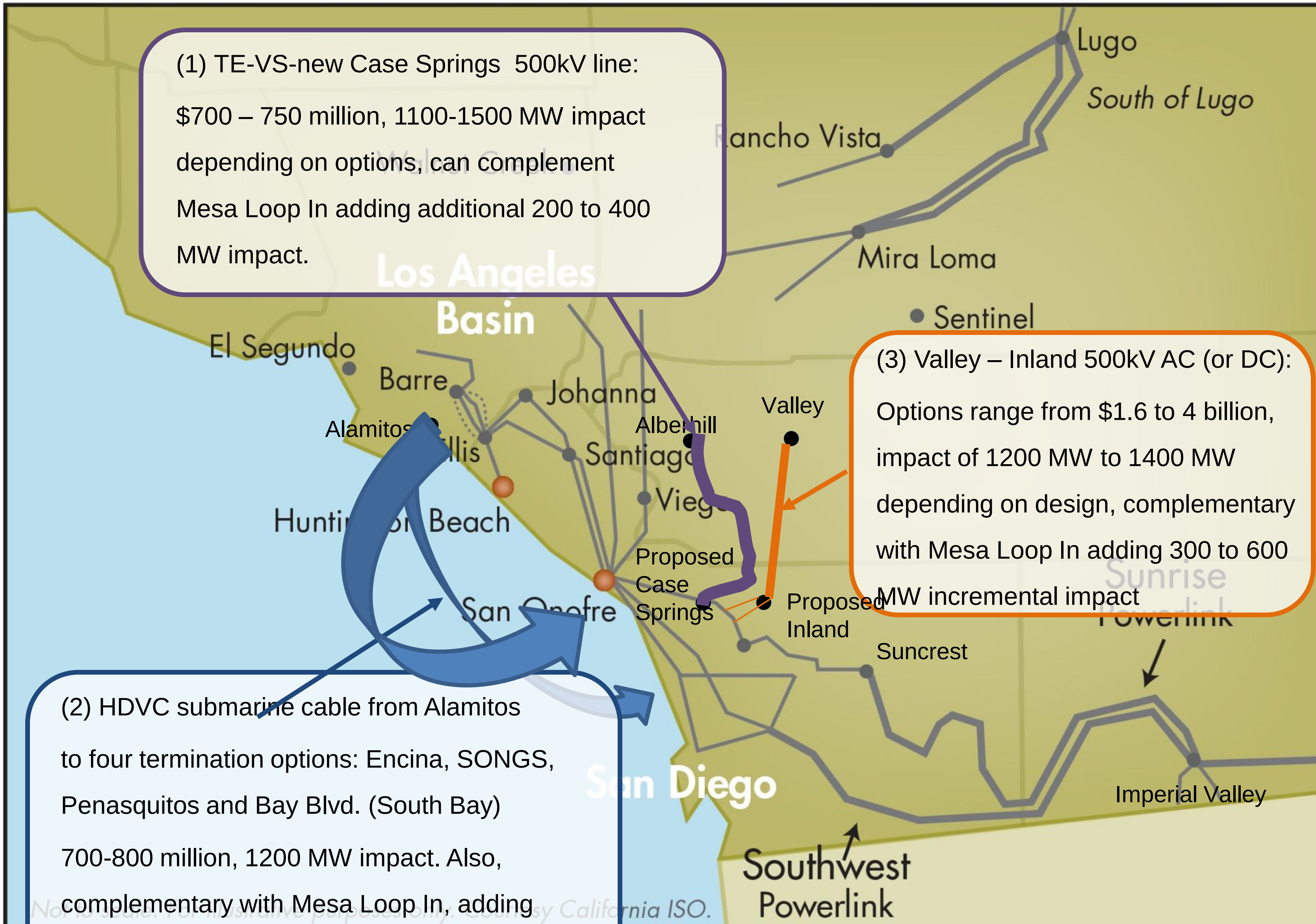
Group I: Transmission Upgrades Optimizing Use of Existing Transmission Lines (cont'd)



Summary of Costs and Benefits of Group I Transmission Upgrades

No.	Transmission Upgrade Option	Proposed In-Service Date	Estimated Cost ($ Million)	Local Resources Reduction Benefits (MW)
1	Additional 450 MVAR of dynamic reactive support at San Luis Rey (i.e., two 225 MVAR synchronous condensers)	June 2018 for permanent installation at SONGS Mesa or near vicinity (San Luis Rey)	~$80 M	-100 to -200 (benefits in 2018; when coupled with other projects (i.e., items 2 and 3 below, it will be part of the benefits of those projects)
2	Imperial Valley Flow Controller (IV B2BDC or Phase Shifter) – for emergency flow control to prevent overloading on CFE line and voltage collapse under Category C.3 contingency	June 2018	$240 - $300 M	-400 to -840
3	Mesa Loop-In Project	December 2020	$464 - $614 M	-300 to -640
	TOTAL		$784 - $994 M	-800 to -1680

Group II: New Transmission Lines Strengthening LA Basin and San Diego Connection



(1) TE-VS-new Case Springs 500kV line:

$700 – 750 million, 1100-1500 MW impact depending on options, can complement Mesa Loop In adding additional 200 to 400 MW impact.

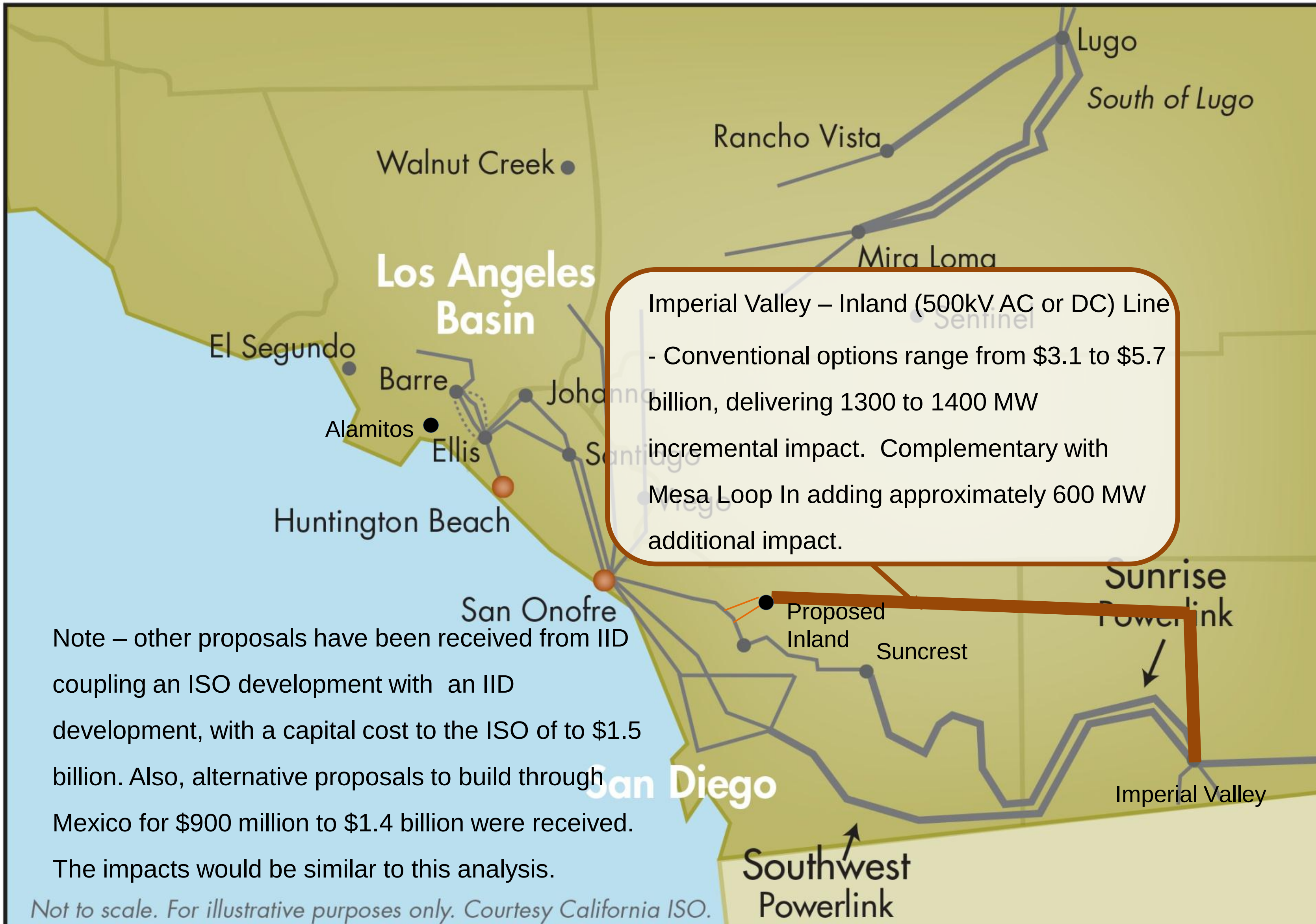
(2) HDVC submarine cable from Alamitos to four termination options: Encina, SONGS, Penasquitos and Bay Blvd. (South Bay)

700-800 million, 1200 MW impact. Also, complementary with Mesa Loop In, adding 550 MW incremental impact.

(3) Valley – Inland 500kV AC (or DC):

Options range from $1.6 to 4 billion, impact of 1200 MW to 1400 MW depending on design, complementary with Mesa Loop In adding 300 to 600 MW incremental impact

Group III: New Transmission Into the Greater LA Basin/San Diego Area



Imperial Valley – Inland (500kV AC or DC) Line

- Conventional options range from $3.1 to $5.7 billion, delivering 1300 to 1400 MW incremental impact. Complementary with Mesa Loop In adding approximately 600 MW additional impact.

Note – other proposals have been received from IID coupling an ISO development with an IID development, with a capital cost to the ISO of to $1.5 billion. Also, alternative proposals to build through Mexico for $900 million to $1.4 billion were received. The impacts would be similar to this analysis.

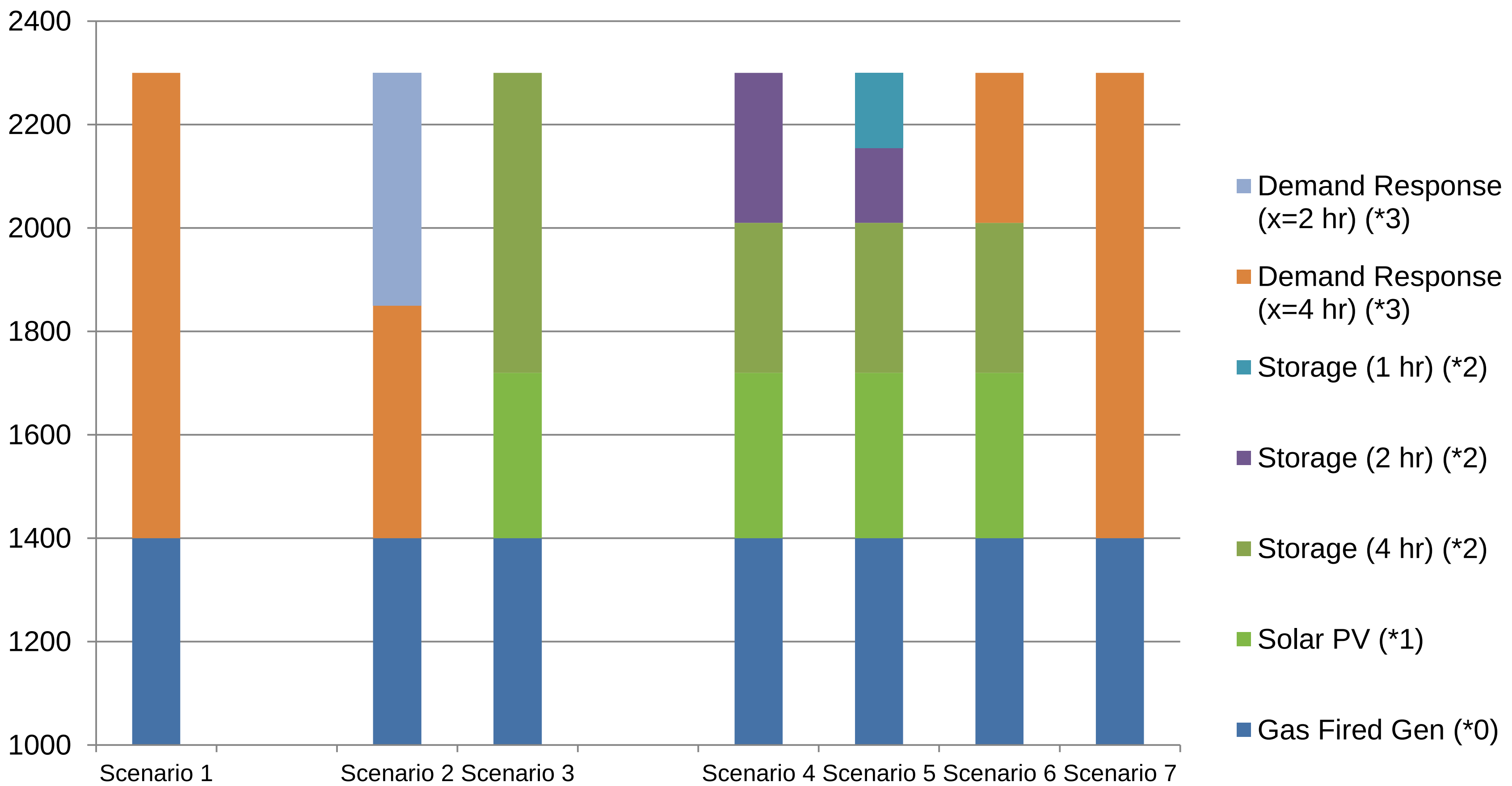
Local Preferred Resources

- Focused on testing effectiveness of procurement options for already authorized procurement and requests for authorization of additional procurement.

- More details are available in a separate presentation on non-conventional transmission alternative

Local Preferred Resources (cont'd) – Scenarios

- SCE provided 7 scenarios (authorized plus requested procurement)



(*0) CCGT @ALMITOSW, CT else
(*1) Solar PV MWs represent installed capacity
(*2) All storage resources are available x hours per day and three days in a row, year-round

STUDY SCENARIOS: 1, 3 & 4

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Conventional Local Resource Needs (2018 & 2023) and Additional Dynamic Reactive Support (for comparison purposes)

Year	Option	Brief Description	Local Resource Needs (MW)				Resource Reduction Benefits (MW)
			SW LA Basin	Eastern LA Basin	San Diego sub-area	Total SONGS Study Area	
2018	2018 New Local Resource Needs	New local resource needs for summer 2018 (1-in-10 loads)	260*	640*	1,048**	1,948	
2018	2018 New Local Resource Needs + Additional Dynamic Reactive Supports	Either convert one SONGS unit to 700 MVAR synchronous condenser (or alternatively install additional support at SONGS Mesa and nearby San Luis Rey)	260	640	820	1,720	-228
2023	Additional new local resources needs for 2023	New local resource needs beyond 2018; assumes additional reactive support (700 MVAR above)	3,462	-640	340	3,162	
2023	Total new local resource needs by 2023	**Total** local resource needs by 2023 (2018 + additional for 2023)	3,722	0	1,160	4,882***	
2023	Total With additional dynamic reactive support (400 MVAR at SONGS)	Additional 400 MVAR dynamic reactive support at SONGS (or SONGS Mesa)	3,722	0	1,019	4,741	-141 (additional VAR support no longer as effective)

Notes:

* Assuming continued operation of aging Long Beach and Etiwanda facilities for 2018 – 2022 (these are non-OTC plants; CPUC assumes retirement due to aging facilities for LTPP Track 4; generation owner has not announced or indicated plan for retirement)

** Assuming Encina power plant retires in 2018 due to once-through cooled compliance (12/31/2017)

*** Total Study Area's load growth from 2022 to 2023 is 465 MW (2011 forecast)

The ISO's path forward includes immediate recommendations and further study:

- Recommend the "Group I" projects now to provide a balanced and significant step forward in addressing local needs with:
  - Minimal footprint (compared to Group II or III projects), higher regulatory certainty and lower cost)
  - Projects that provide long term benefits even if other transmission reinforcements are pursued
  - Relying heavily on preferred resources and also leaves a modest amount of residual need for future cycles as other uncertainties are addressed, a margin for forecast uncertainty, and possible future procurement of preferred resources

- Continue to refine needs and analyze longer lead-time future reinforcements such as Group II (LA/San Diego connector projects) in future planning cycles:
  - When more clarity is available regarding preferred resource development
  - With more current load forecast and energy efficiency forecast information

- Provide input into state policy discussions of the effectiveness of the Group II and Group III transmission projects.

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Evaluation of Preferred Resource and Storage Alternatives to Transmission and Generation in the LA Basin and San Diego Areas

Draft 2013-2014 ISO Transmission Plan Stakeholder Meeting

Robert Sparks, David Le
Regional Transmission
February 12, 2014

Preferred Resource Scenarios

- Preferred resource scenario input data from SCE for the LA Basin
- Supplemented with assumptions for San Diego;
- and with DG Commercial Interest portfolio

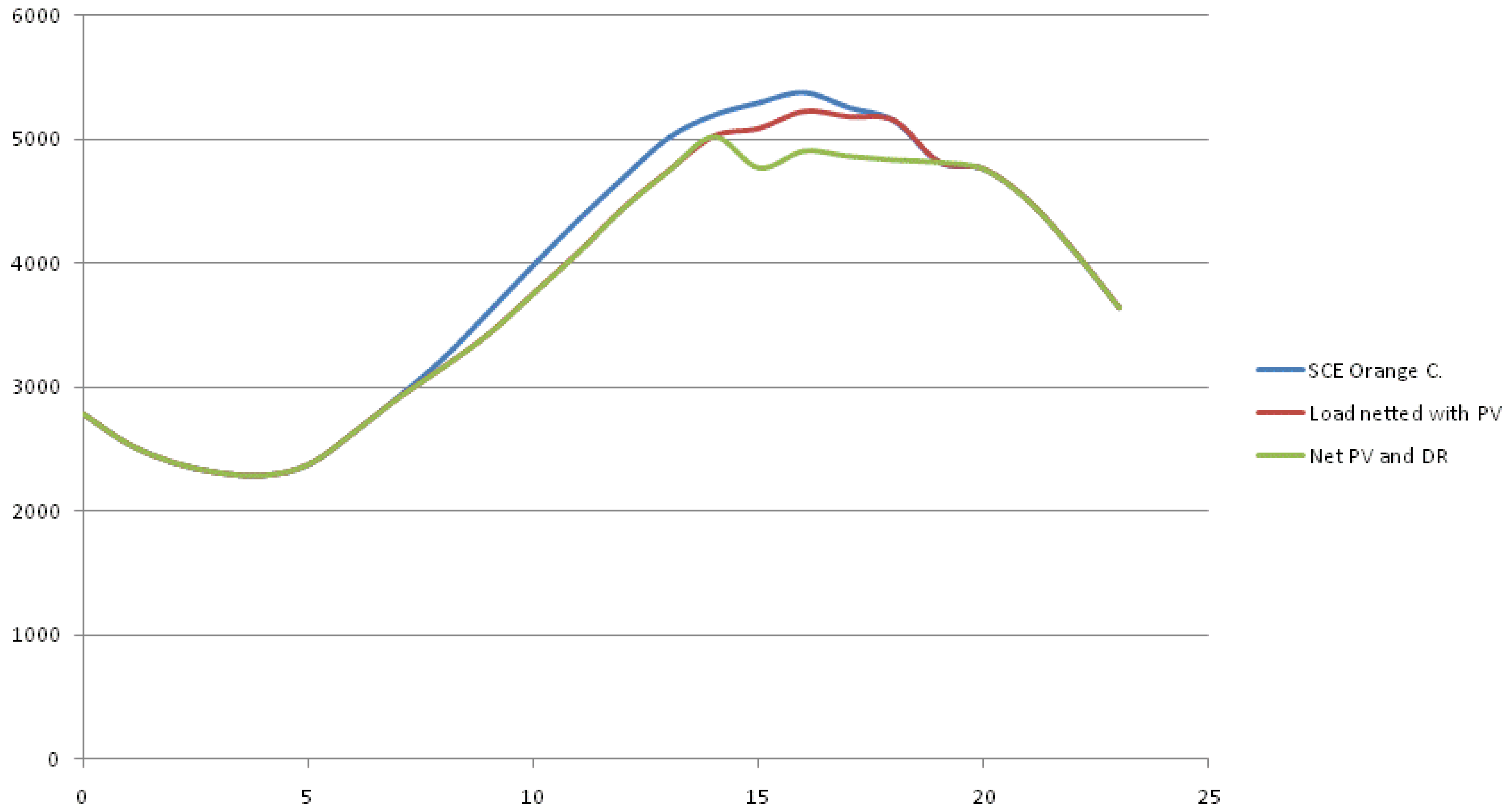
LA Basin Preferred Resource Scenario Data

	Gas Fired Gen (*0)	Solar PV (*1)	Storage (4 hr) (*2)	Storage (2 hr) (*2)	Storage (1 hr) (*2)	Demand Response (x=4 hr) (*3)	Demand Response (x=2 hr) (*3)
Scenario 1	1400	0	0	0	0	900	0
Scenario 2	1400	0	0	0	0	450	450
Scenario 3	1400	320	580	0	0	0	0
Scenario 4	1400	320	290	290	0	0	0
Scenario 5	1400	320	290	145	145	0	0
Scenario 6	1400	320	290	0	0	290	0
Scenario 7	1400	0	0	0	0	900	0

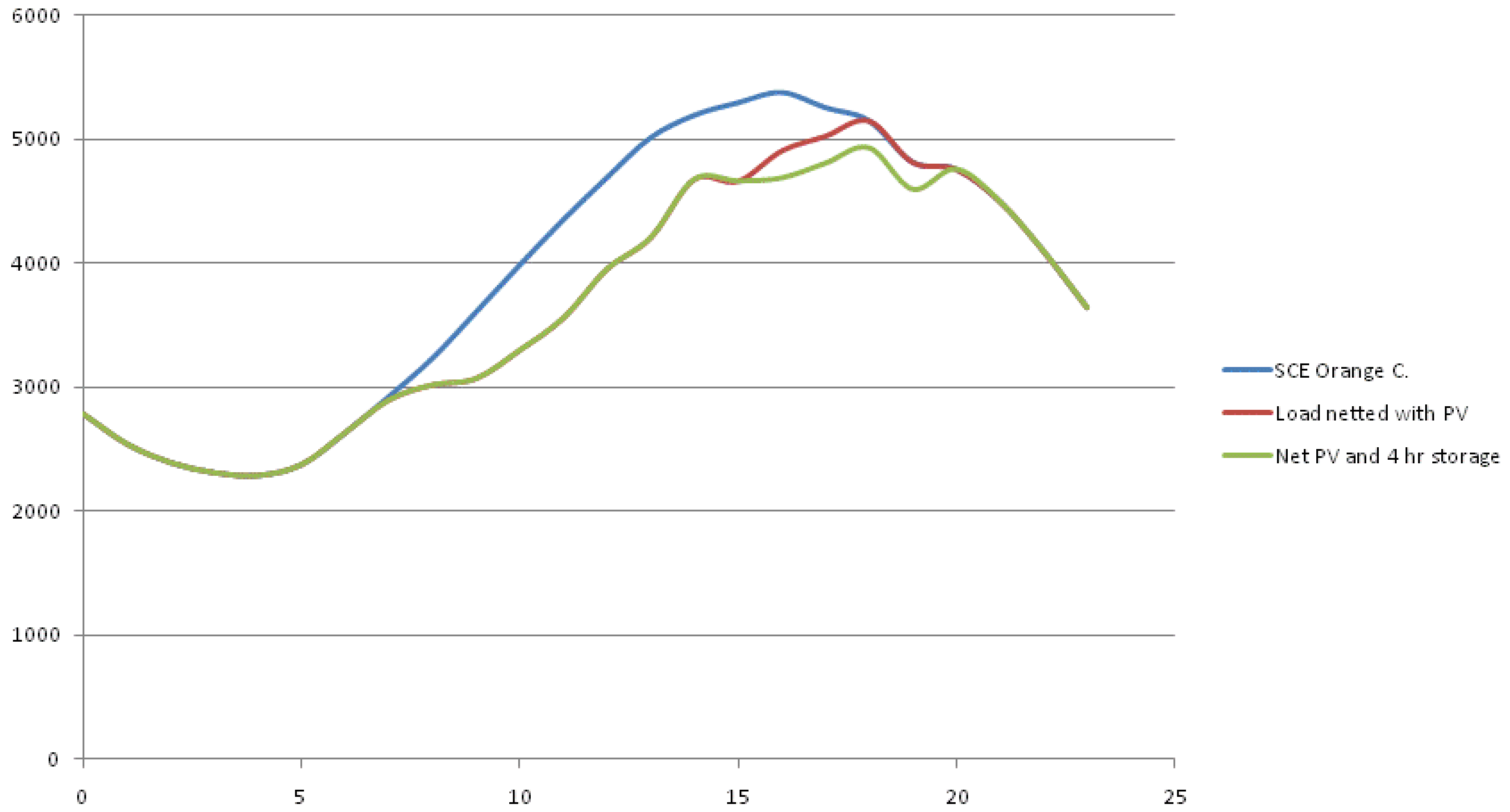
Additional Preferred Resource Scenario Data Assumptions

- Assumed 200 MW of 6-hour demand response in San Diego for all scenarios
- Assumed 100 MW of 4-hour storage in San Diego for all scenarios
- Deployed preferred resources to minimize highest net load for Orange County, San Diego, and the rest of LA Basin

SCE SCENARIO 1, ORANGE COUNTY



SCE SCENARIO 3, ORANGE COUNTY



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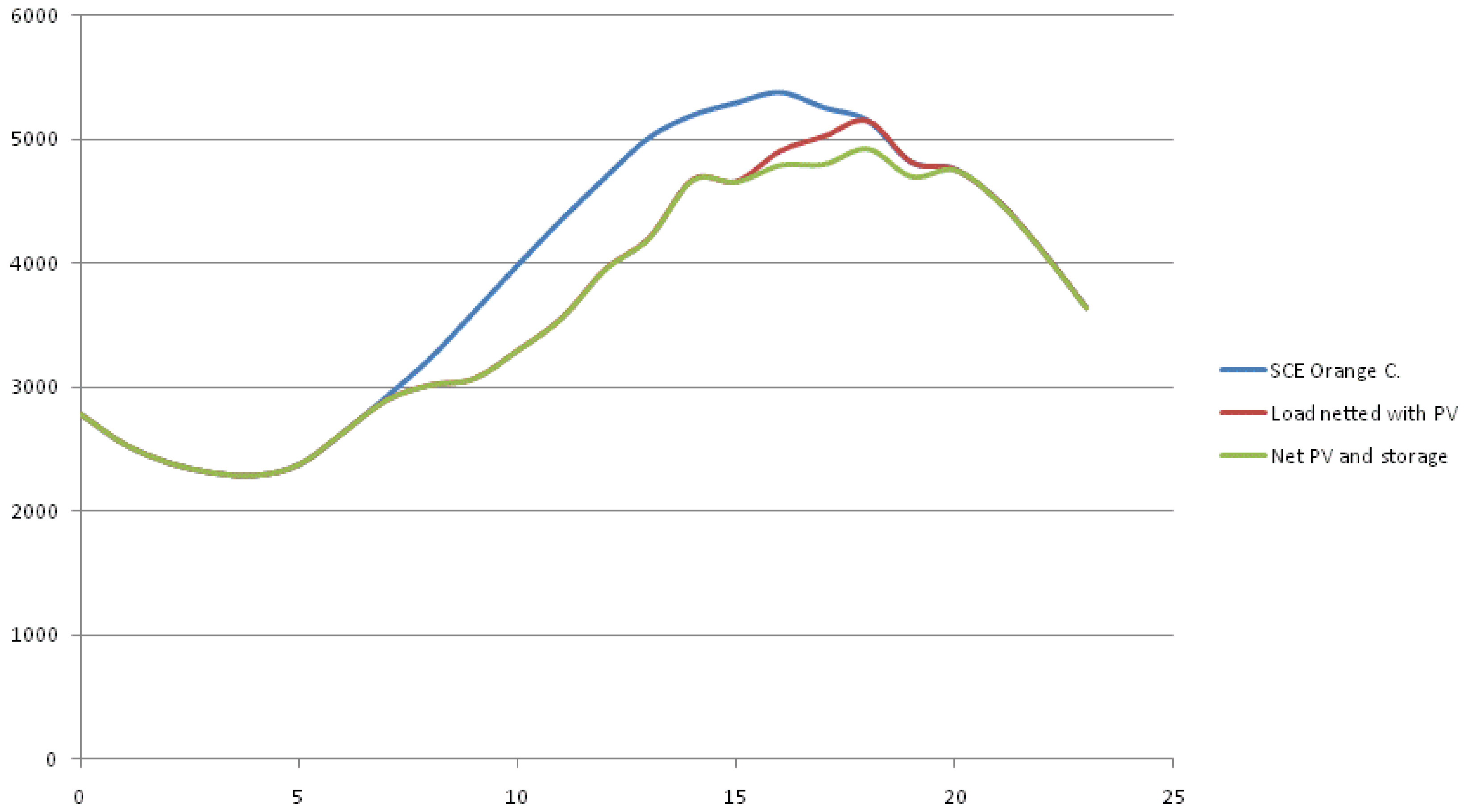
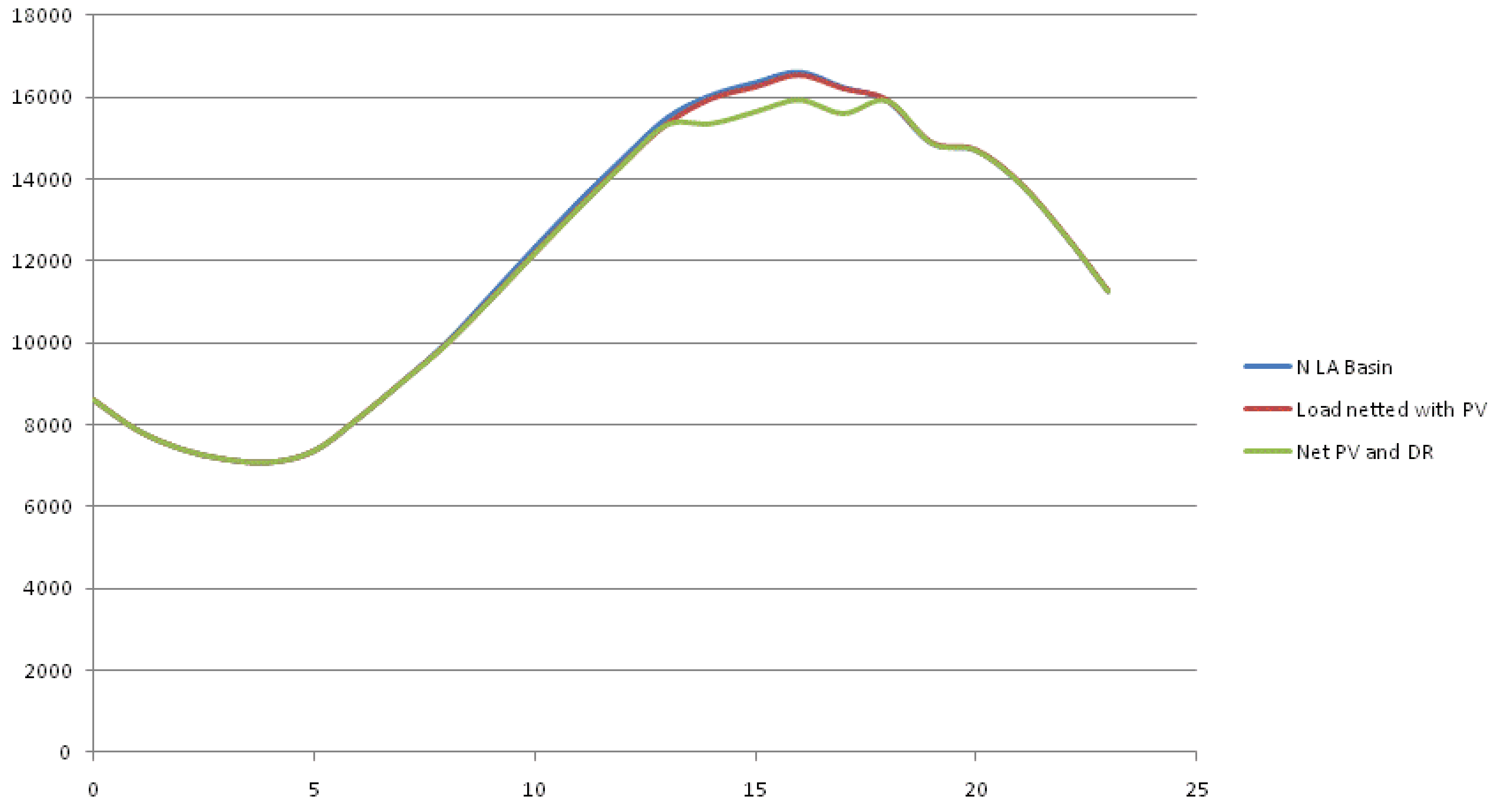
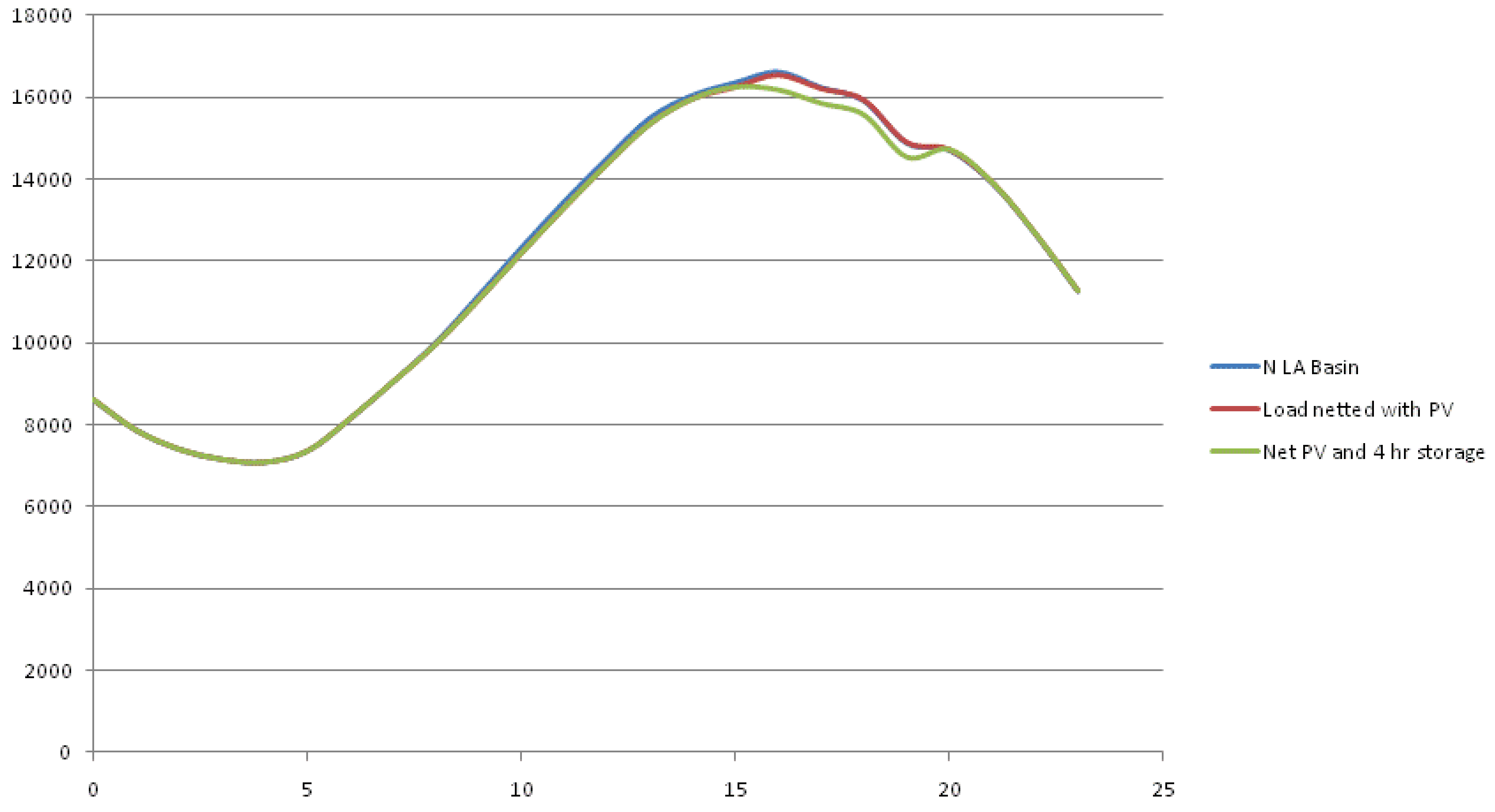
SCE SCENARIO 4, ORANGE COUNTY



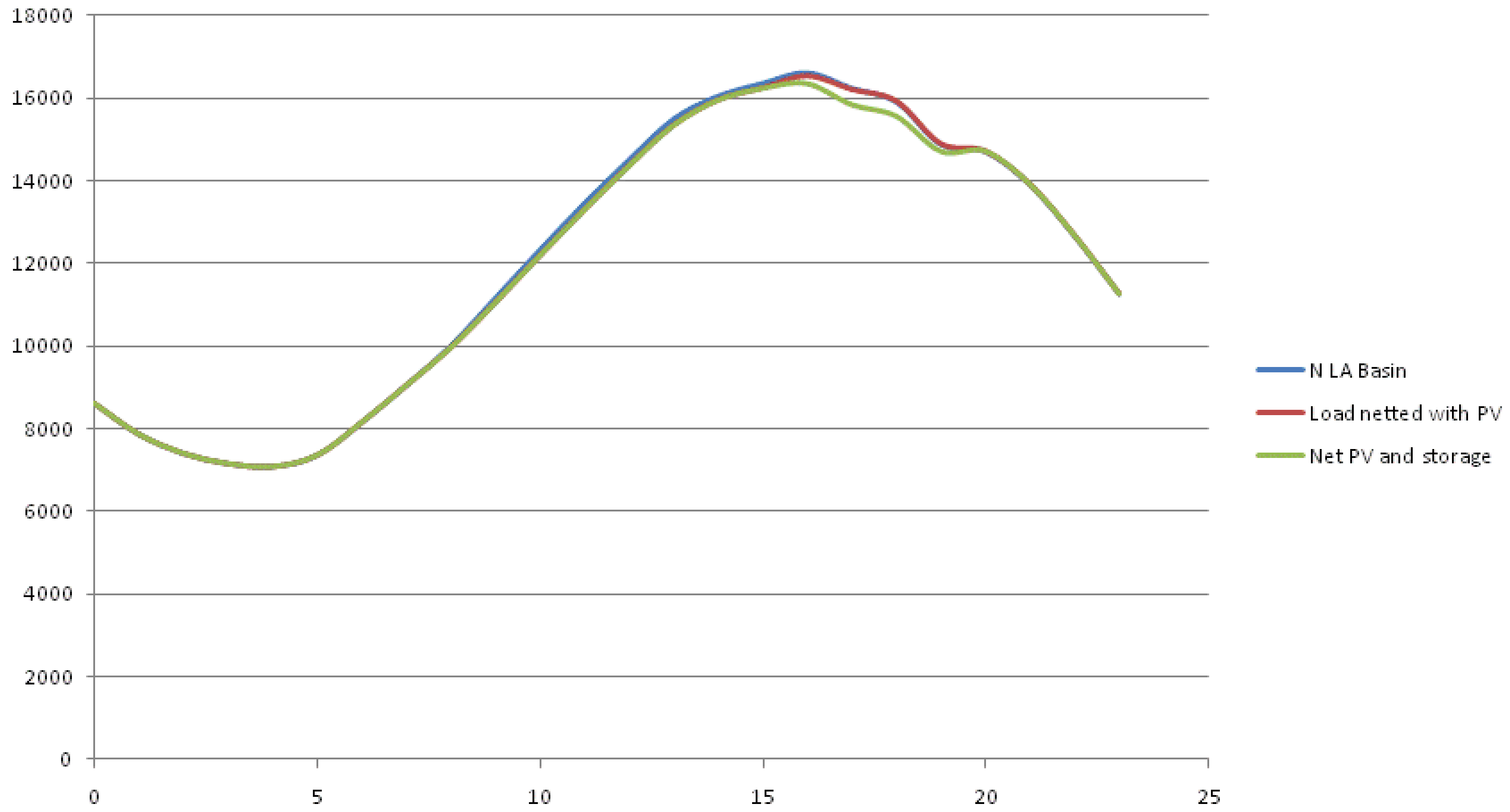
SCE SCENARIO 1, N LA BASIN



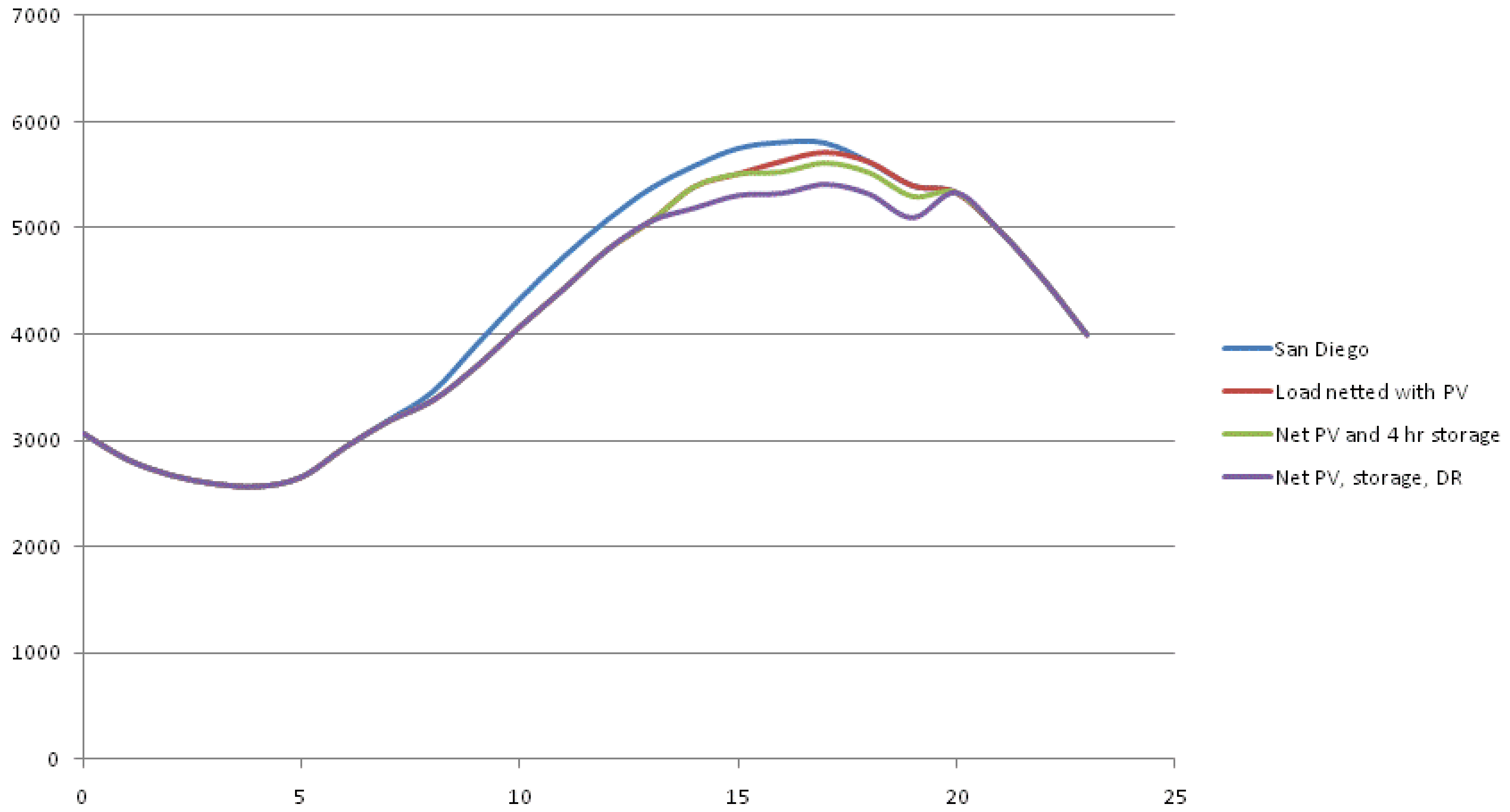
SCE SCENARIO 3, N LA BASIN



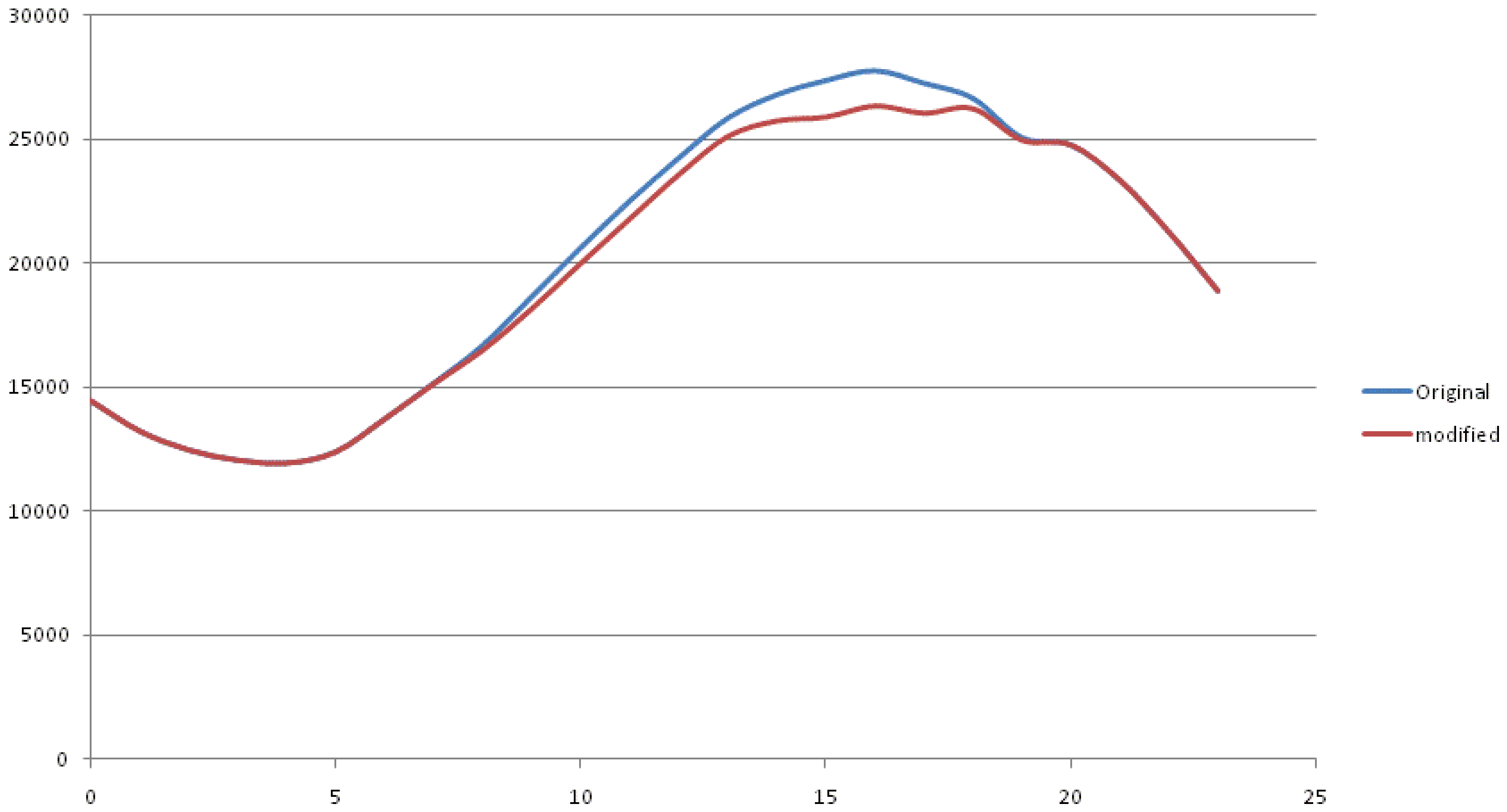
SCE SCENARIO 4, N LA BASIN



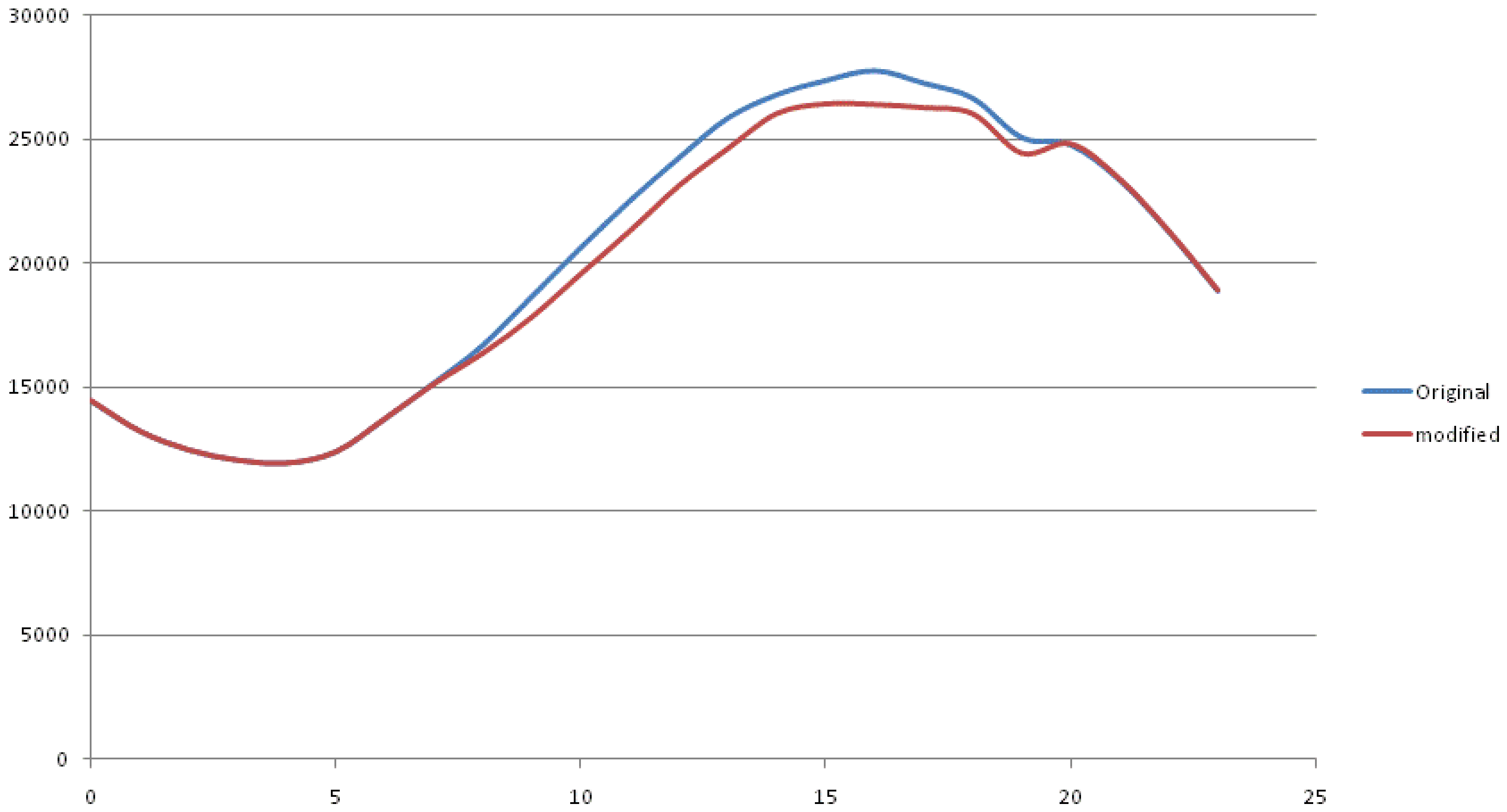
SAN DIEGO, ALL SCENARIOS



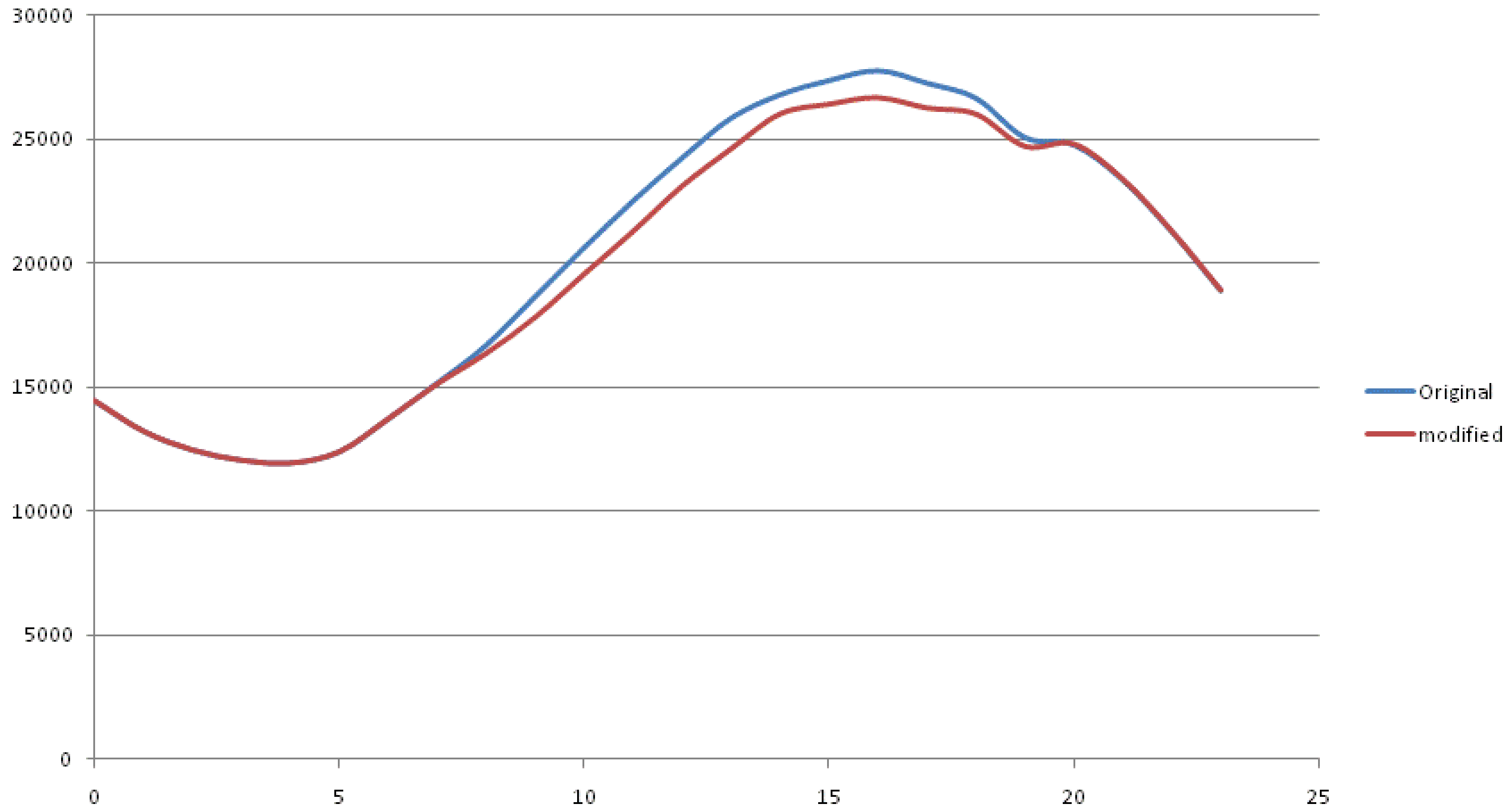
SCE SCENARIO 1, Total Study Area Load



SCE SCENARIO 3, Total Study Area Load



SCE SCENARIO 4, Total Study Area Load



Different Subareas Peak at Different hours for different Scenarios

Scenario	OC pk hr	SDGE pk hr	N LA pk hr	Total Study Area pk hr
1	14	17	16	16
3	18	17	15	15
4	18	17	15	16

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Studied two operating hours for each scenario

	Run	hr	SCE load % of 1 in 10	SDGE load % of 1 in 10	solar % of installed	OC DR	NLA DR	SCE storage	SDGE DR	SDGE storage
Scenario 1	1	14	97%	96%	49%	315	585	none	200	100
	2	17	98%	100%	22%	0	585	none	200	100
Scenario 3	1	15	98.50%	99%	60%	none	none	0	200	0
	2	18	96%	97%	0%	none	none	580	200	100
Scenario 4	1	16	100.00%	100%	45%	none	none	290	200	100
	2	18	96%	97%	0%	none	none	580	200	100

Scenario Analysis Study Results

Scenario	Hour for study scenario	Major Transmission Upgrades?	SCE (Assuming Track 1 + SCE-proposed Track 4 = 1800 + 500 = 2300 MW)								SDG&E (Assuming Track 1 + proposed Track 4 = 308 + 550 = 858 where 10 MW goes to Escondido peaker increase)				Study Results for Critical N-1-1 Contingency
			Gas Fired Gen (*0)	Solar PV (*1)	Storage (4 hr) (*2)	Storage (2 hr) (*2)	Storage (1 hr) (*2)	DR (x=4 hr) (*3)	DR (x=2 hr) (*3)	Percentage of Peak Loads	Gas Fired Gen (*0.1)	Storage (4 hr) (*2)	DR (x=4 hr) (*3)	Percentage of Peak Loads	
1.1.1	14:00 hr	Mesa loop-in and IV B2BDC	1400	0	0	0	0	585 (NLA) + 181 (existing program)	0	97%	550	100	200 (new) + 17 (existing program)	96%	Case convergent; lower loads modeled due to non-peak hours
1.1.2	14:00 hr	Mesa loop-in and IV PS	1400	0	0	0	0	585 (NLA) + 181 (existing program)	0	97%	550	100	200 (new) + 17 (existing program)	96%	Case convergent; lower loads modeled due to non-peak hours

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Scenario Analysis Study Results (cont'd)

Scenario	Hour for study scenario	Major Transmission Upgrades?	SCE (Assuming Track 1 + SCE-proposed Track 4 = 1800 + 500 = 2300 MW)								SDG&E (Assuming Track 1 + proposed Track 4 = 308 + 550 = 858 where 10 MW goes to Escondido peaker increase)				Study Results for Critical N-1-1 Contingency
			Gas Fired Gen (*0)	Solar PV (*1)	Storage (4 hr) (*2)	Storage (2 hr) (*2)	Storage (1 hr) (*2)	DR (x=4 hr) (*3)	DR (x=2 hr) (*3)	Percentage of Peak Loads	Gas Fired Gen (*0.1)	Storage (4 hr) (*2)	DR (x=4 hr) (*3)	Percentage of Peak Loads	
1.2.1	17:00 hr	None other than dynamic reactive supports	1400	0	0	0	0	900	0	98%	550	100	200	100%	Case divergent without additional transmission upgrades/mitigation
1.2.2	17:00 hr	Adding Mesa loop-in													Case divergent
1.2.3	17:00 hr	1.2.2 + more DR (i.e., existing DR used in LTPP Track 4 for post first contingency)						+181 (existing program; additional to above)					+17 (existing program; additional to above)		Case divergent

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Shaping a Renewed Future

Scenario Analysis Study Results (cont'd)

Scenario	Hour for study scenario	Major Transmission Upgrades?	SCE (Assuming Track 1 + SCE-proposed Track 4 = 1800 + 500 = 2300 MW)								SDG&E (Assuming Track 1 + proposed Track 4 = 308 + 550 = 858 where 10 MW goes to Escondido peaker increase)				Study Results for Critical N-1-1 Contingency
			Gas Fired Gen (*0)	Solar PV (*1)	Storage (4 hr) (*2)	Storage (2 hr) (*2)	Storage (1 hr) (*2)	DR (x=4 hr) (*3)	DR (x=2 hr) (*3)	Percentage of Peak Loads	Gas Fired Gen (*0.1)	Storage (4 hr) (*2)	DR (x=4 hr) (*3)	Percentage of Peak Loads	
1.2.4	17:00 hr	1.2.3 + IV flow controller (IV B2BDC)						+181 (existing program)					+17 (existing program; additional to above)		Case convergent Comments - for higher loads, it's better to have "reliable" DR spread out at various load bus locations.
1.2.5	17:00 hr	1.2.3 + IV flow controller (phase shifter)						+181 (existing program)					+17 (existing program; additional to above)		Case divergent

Scenario Analysis Study Results (cont'd)

Scenario	Hour for study scenario	Major Transmission Upgrades?	SCE (Assuming Track 1 + SCE-proposed Track 4 = 1800 + 500 = 2300 MW)								SDG&E (Assuming Track 1 + proposed Track 4 = 308 + 550 = 858 where 10 MW goes to Escondido peaker increase)				Study Results for Critical N-1-1 Contingency
			Gas Fired Gen (*0)	Solar PV (*1)	Storage (4 hr) (*2)	Storage (2 hr) (*2)	Storage (1 hr) (*2)	DR (x=4 hr) (*3)	DR (x=2 hr) (*3)	Percentage of Peak Loads	Gas Fired Gen (*0.1)	Storage (4 hr) (*2)	DR (x=4 hr) (*3)	Percentage of Peak Loads	
3.1.1	15:00 hr	Mesa loop-in modeled	1400	320 (installed) (modeled at 60% (192 MW) due to hour of the study)	580	0	0	+181 (existing program)	0	98.5%	550	100	200 (+ 17 MW from existing program)	99%	Divergent
3.1.2	15:00 hr	3.1.1 + IV B2BDC													Convergent
3.1.3	15:00 hr	3.1.1 + Adding IV PS													Convergent

Scenario Analysis Study Results (cont'd)

Scenario	Hour for study scenario	Major Transmission Upgrades?	SCE (Assuming Track 1 + SCE-proposed Track 4 = 1800 + 500 = 2300 MW)								SDG&E (Assuming Track 1 + proposed Track 4 = 308 + 550 = 858 where 10 MW goes to Escondido peaker increase)				Study Results for Critical N-1-1 Contingency
			Gas Fired Gen (*0)	Solar PV (*1)	Storage (4 hr) (*2)	Storage (2 hr) (*2)	Storage (1 hr) (*2)	DR (x=4 hr) (*3)	DR (x=2 hr) (*3)	Percentage of Peak Loads	Gas Fired Gen (*0.1)	Storage (4 hr) (*2)	DR (x=4 hr) (*3)	Percentage of Peak Loads	
3.2.1	18:00 hr	Adding Mesa loop-in project	1400	320 (modeled as 0 MW due to time studied at 6 p.m.)	580	0	0	+181 (existing program; additional to above)	0	96%	550	100	200 (+17 MW from existing program)	97%	Divergent
3.2.2	18:00 hr	3.2.1 + Adding IVB2BDC													Convergent
3.2.3	16:00 hr	3.2.1 + Adding IV PS													Convergent

Scenario Analysis Study Results (cont'd)

Scenario	Hour for study scenario	Major Transmission Upgrades?	SCE (Assuming Track 1 + SCE-proposed Track 4 = 1800 + 500 = 2300 MW)								SDG&E (Assuming Track 1 + proposed Track 4 = 308 + 550 = 858 where 10 MW goes to Escondido peaker increase)				Study Results for Critical N-1-1 Contingency
			Gas Fired Gen (*0)	Solar PV (*1)	Storage (4 hr) (*2)	Storage (2 hr) (*2)	Storage (1 hr) (*2)	DR (x=4 hr) (*3)	DR (x=2 hr) (*3)	Percentage of Peak Loads	Gas Fired Gen (*0.1)	Storage (4 hr) (*2)	DR (x=4 hr) (*3)	Percentage of Peak Loads	
4.1.1	16:00 hr	Adding T-1 and T-2A options (Mesa loop-in + IV B2BDC)	1400	320 (modeled as 45% of installed capacity)	290	290 (modeled as 0 MW for this scenario)	0	0	0	100%	550	100	200	100%	Divergent
4.1.2	16:00 hr	Adding T-1 and T-2A options (Mesa loop-in + IV B2BDC)	1400	320	580	0	0	0	0	100%	550	100	200	100%	Case divergent - load is higher for this scenario
4.1.3	16:00 hr	Adding T-1 and T-2B options (Mesa loop-in + IV PS)	1400	320	580	0	0	0	0	100%	550	100	200	100%	Case divergent; resources are not all located in optimal locations (i.e., SW LA Basin or San Diego)

Key Findings from the Scenario Analyses

- None of the proposed resource options would be able to mitigate on their own without transmission upgrades for the most critical Category C (N-1-1) contingency
- Coupled with the recommended bulk transmission upgrades presented for the Southern California bulk transmission system, scenarios 1 and 3 appear to be feasible in mitigating the most critical contingency discussed above.
- Scenario 4 appears to be infeasible due to the shorter duration resources and some conventional resources proposed to be located in less effective location for mitigating the most critical Category C.3 contingency.
- The most effective locations for mitigating post transient voltage instability due to the most critical Category C.3 contingency were determined to be located in the San Diego local capacity area, followed by Southwest LA Basin sub-area.

Reliability Projects Recommended for Approval
San Diego Gas & Electric

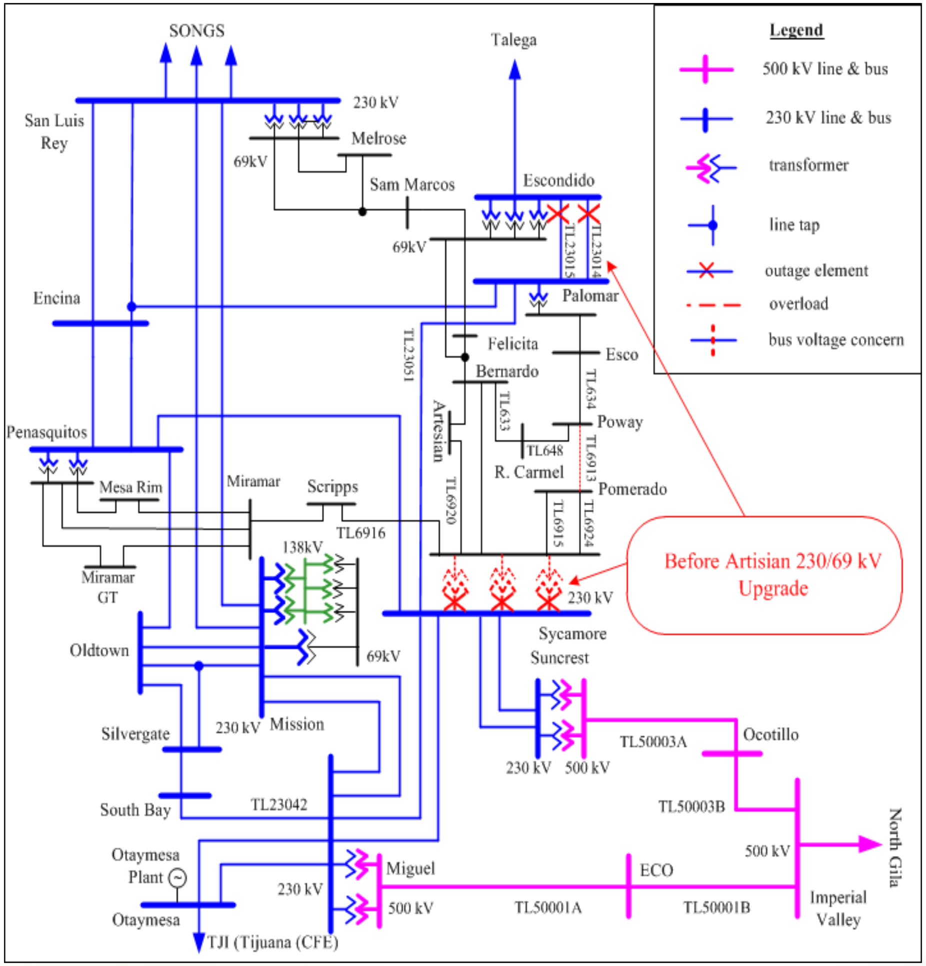
Draft 2013-2014 Transmission Plan Stakeholder Meeting

Frank Chen
Sr. Regional Transmission Engineer
February 12, 2014

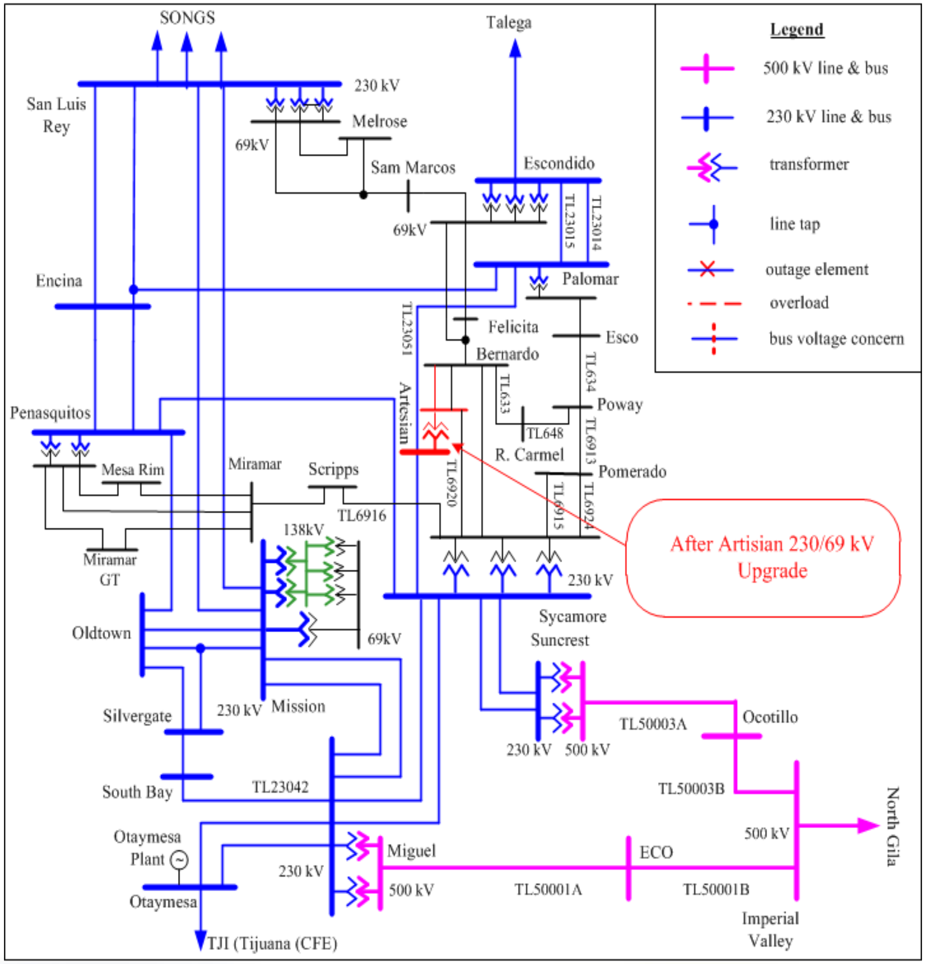
5 Projects Recommended for Approval

1. Artesian 230 kV Sub & loop-in TL23051

Before



After



1. Artesian 230 kV Sub & loop-in TL23051 (cont'd)

Need: NERC Category C overloads (2018), 3rd source for Poway Load Pocket

Project Scope: Upgrade Artesian 69 kV to 230/69 kV sub, loop in TL23051 Sycamore-Palomar 230 kV line nearby, and make rearrangement to have two 69 kV lines from Bernardo to Artesian.

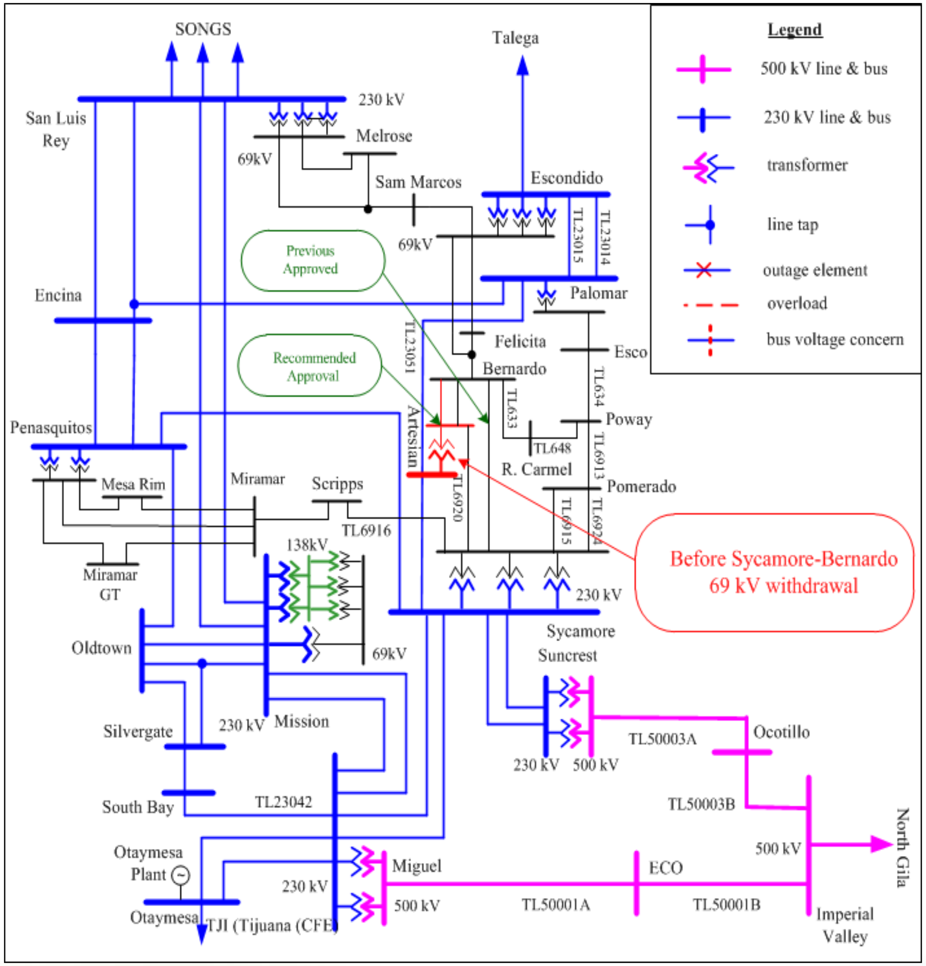
Cost: $44~64 millions (or net of $29~49 millions if Sycamore-Bernardo 69kV project withdrawal is approved)

Other Considered Alternatives:
Replace Sycamore 230/69 kV Banks #70/#71/#72 and add 2nd Pomerado-Poway 69 kV line ($56~79 million), or design a SPS to shed at least 70 MW loads in the Poway Load Pocket, but it may take up to weeks to resume the service even the Category C outages are rare.

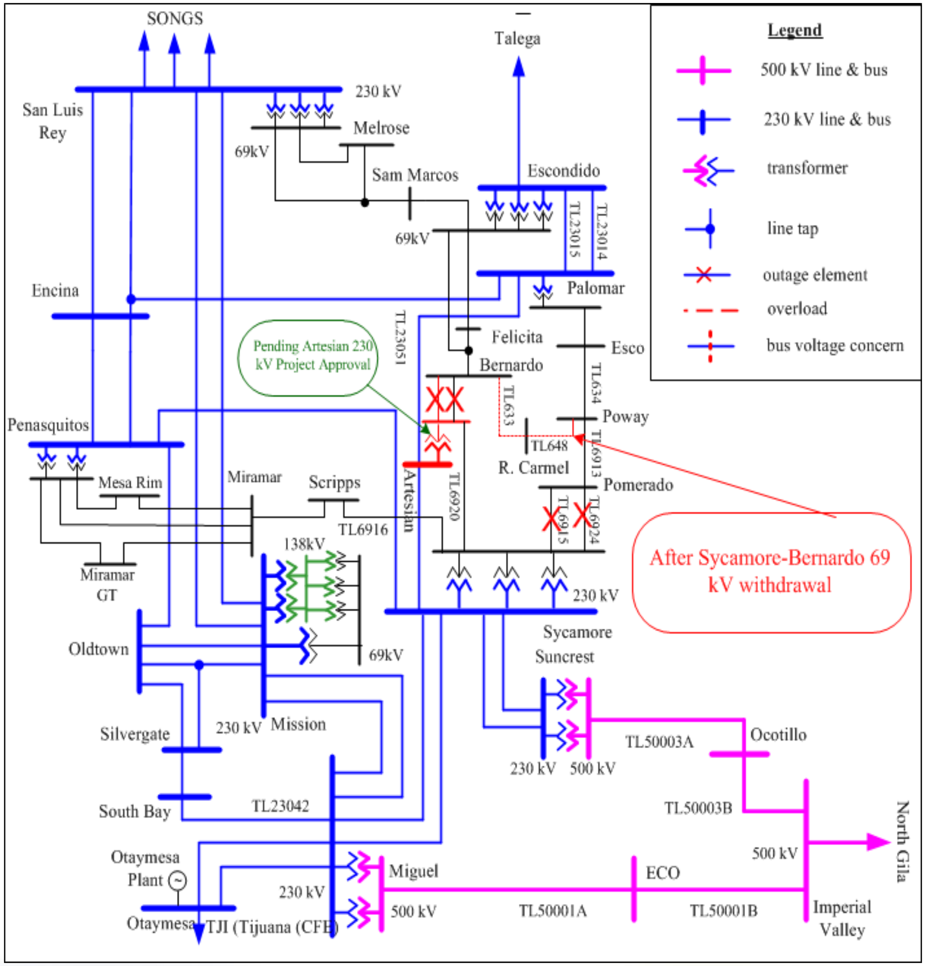
Expected In-Service: June 2016 (pending Sycamore-Bernardo 69 kV project withdrawal approval)

2. Sycamore-Bernardo 69kV Project Replaced by Bernardo-Poway 69 kV lines upgrade

Before



After



2. Sycamore-Bernardo 69kV Project Replaced by Bernardo-Poway 69 kV upgrade

Need: NERC Category B overloads (2016)

Project Scope: Cancel Sycamore-Bernardo 69 kV line project ($43 millions), But upgrade Bernardo-Ranche Carmel & Rancho Carmel-Poway 69 kV lines as replacement ($28 millions)

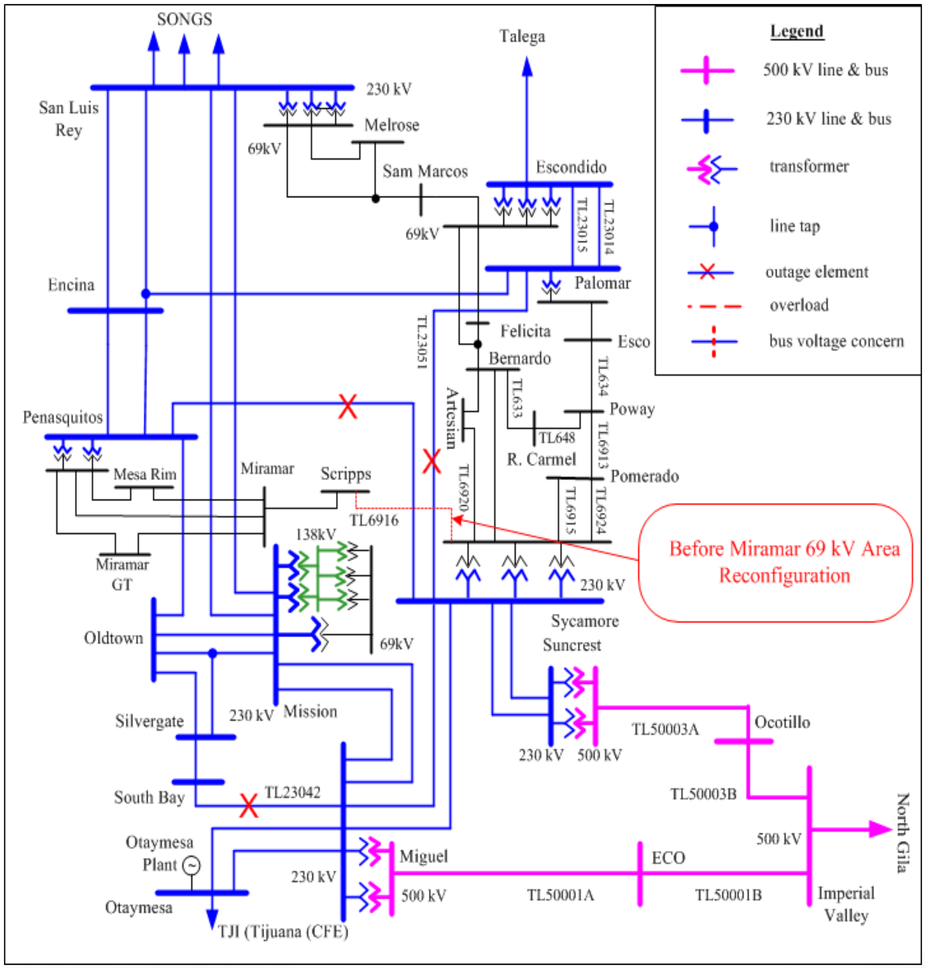
Cost: -($15 millions)

Other Considered Alternatives:
Withdraw Sycamore-Bernardo 69 kV line project, but convert Chicarita 138 kV to 69 kV sub, loop in TL6920/TL6961 and build new Chicarita-Poway & Chicarita-Rancho Carmel 69 kV lines ($29~47 millions)

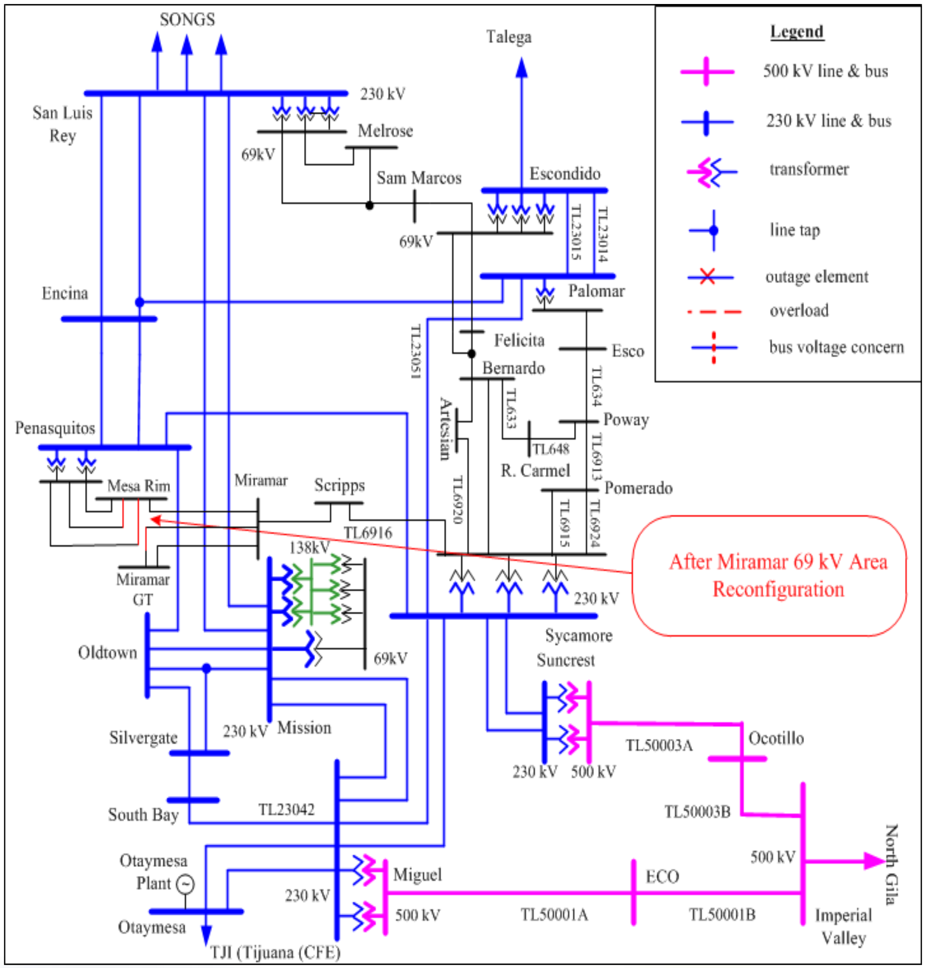
Expected In-Service: June, 2016

3. Miramar-MesaRim 69kV Reconfiguration

Before



After



3. Miramar-MesaRim 69 kV Reconfiguration (cont'd)

Need: NERC Category C overloads (2018)

Project Scope: Reconfigure the Scripps-Miramar-MesaRim 69 kV system by re-directing generation flow out of Miramar Peakers and minimize 69 kV line to Pennasquitos

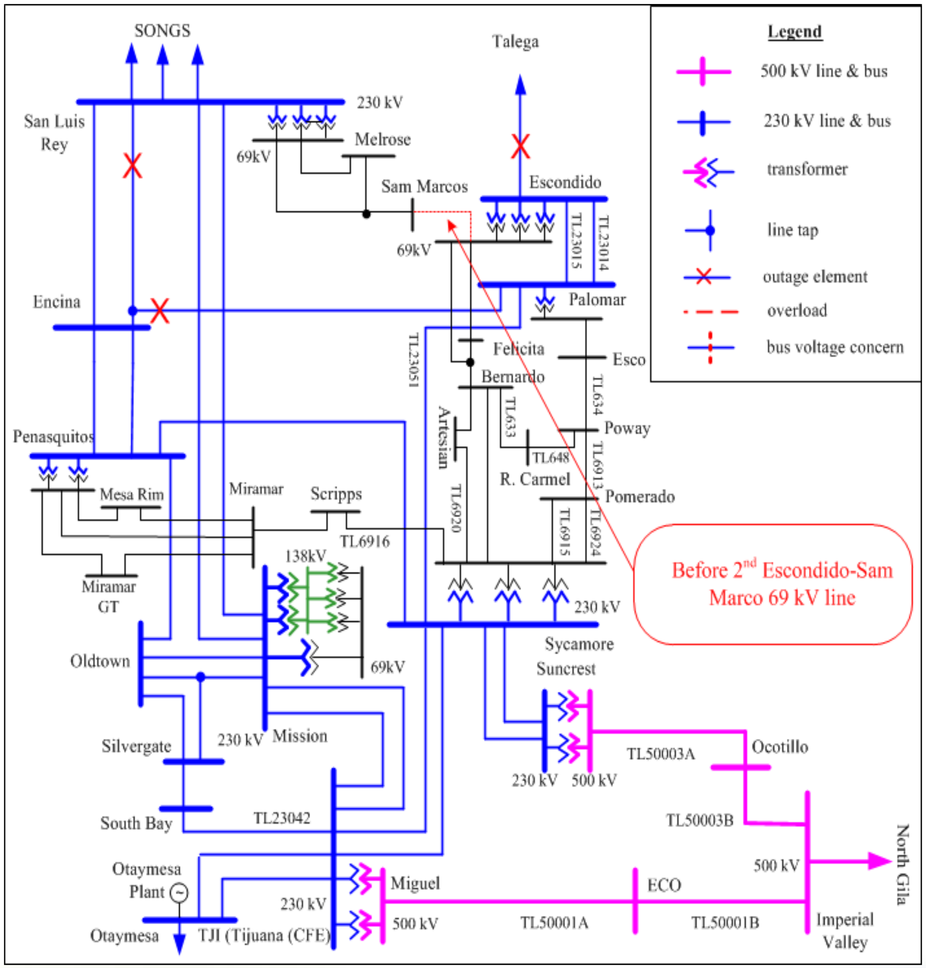
Cost: \$5~7 millions

Other Considered Alternatives:
Build 2nd Sycamore-Scripps 69 kV line (\$25~35 million), or SPS to shed at least 95 MW loads in the Scripps and Miramar areas.

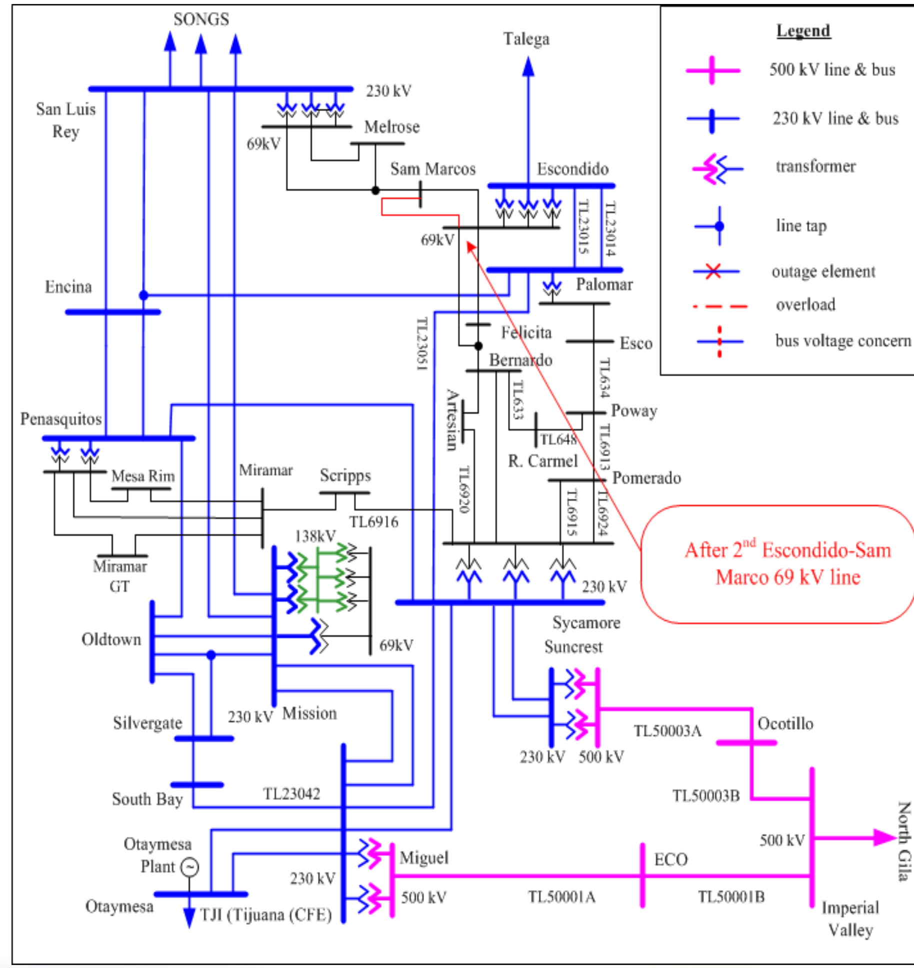
Expected In-Service: June 2018

4. Second Escondido-San Marcos 69 kV Line

Before



After



4. Second Escondido-San Marcos 69 kV Line (cont'd)

<u>Need:</u> NERC Category C overloads (2018)

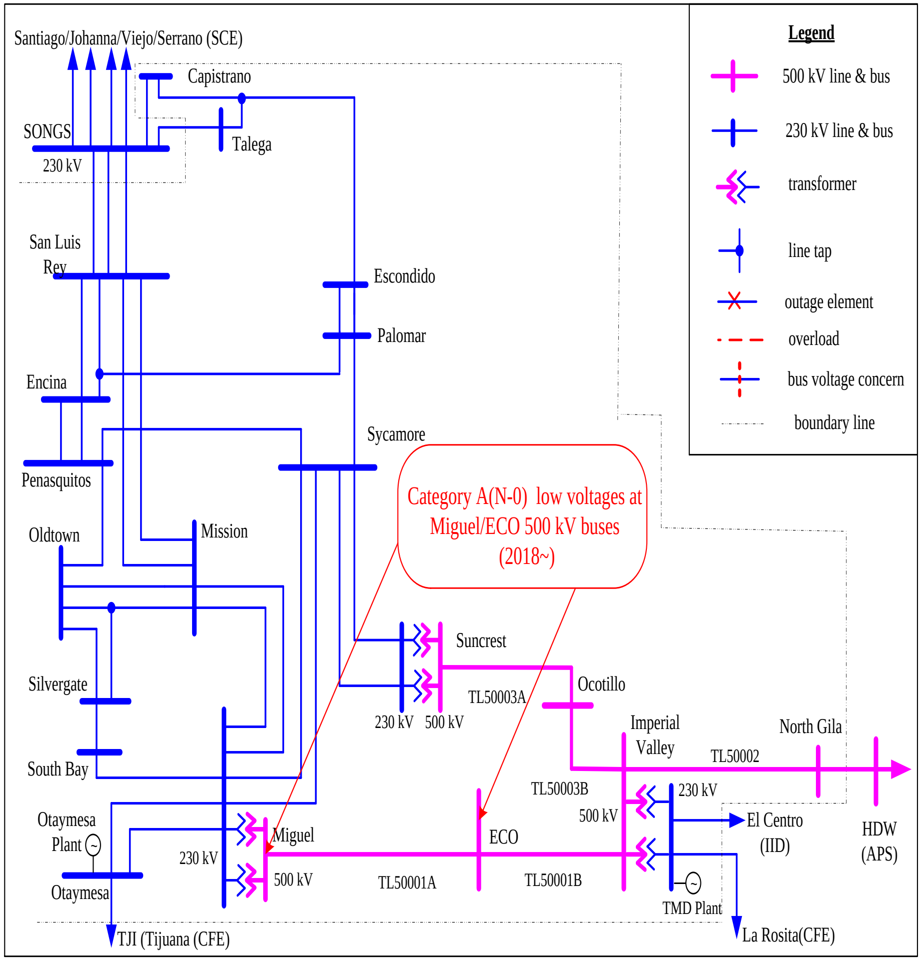
<u>Project Scope:</u> Energize an abandoned 138 kV line and make it 2nd 69 kV line between Escondido and San Marcos

<u>Cost:</u> $18~22 millions

<u>Other Considered Alternatives:</u>
No sound alternative

<u>Expected In-Service</u>: being pushed forward to June 2015

5. Voltage Support at Miguel 500/230 kV Substation



<u>Need:</u> NERC Category A Voltage Violation (2018)

<u>Project Scope:</u> Install up to 375 MVAR of reactive power support at Miguel 500/230 kV substation

<u>Cost:</u> $30~40 millions

<u>Other Considered Alternatives:</u>
No sound alternative

<u>Expected In-Service</u>: June 2018

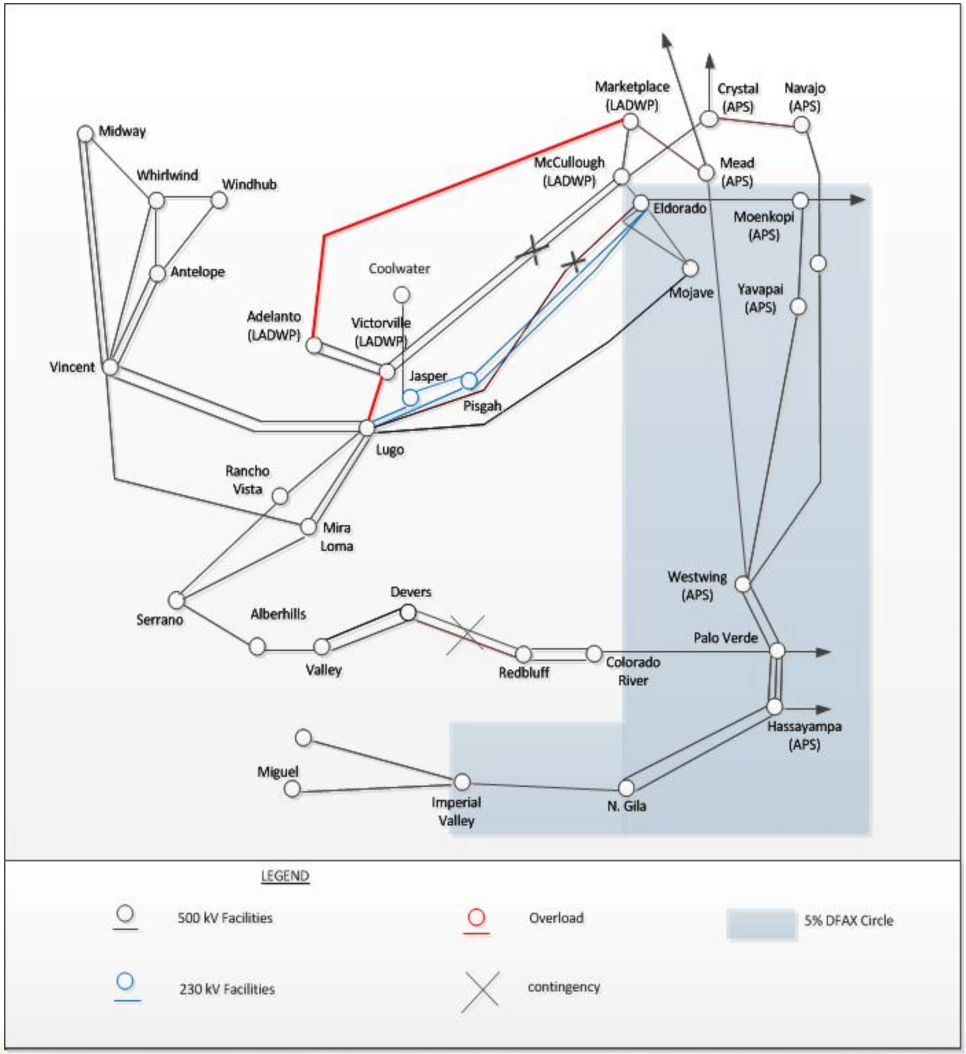
Recommendations on the Policy Driven Projects
SCE and SDGE Areas

Draft 2013-2014 ISO Transmission Plan Stakeholder Meeting

Songzhe Zhu, Luba Kravchuk, Yi Zhang
Regional Transmission - South

February 12, 2014

Lugo – Mohave Series Cap and Terminal Equipment Upgrade



Needs:

- Support deliverability of renewable generation in multiple renewable zones, including Mountain Pass, Eldorado, Riverside East, Tehachapi, Arizona, Imperial Valley and distributed solar.
- Needed for the 33% renewable Commercial Interest Portfolio (base portfolio), High DG, and Environmentally Constrained Portfolio; estimated being needed in 2016.

Project Scope: Upgrade the existing 500kV series capacitor and terminal equipment on the Mohave - Lugo 500kV line to 3800 Amp continuous rating at Mohave Substation.

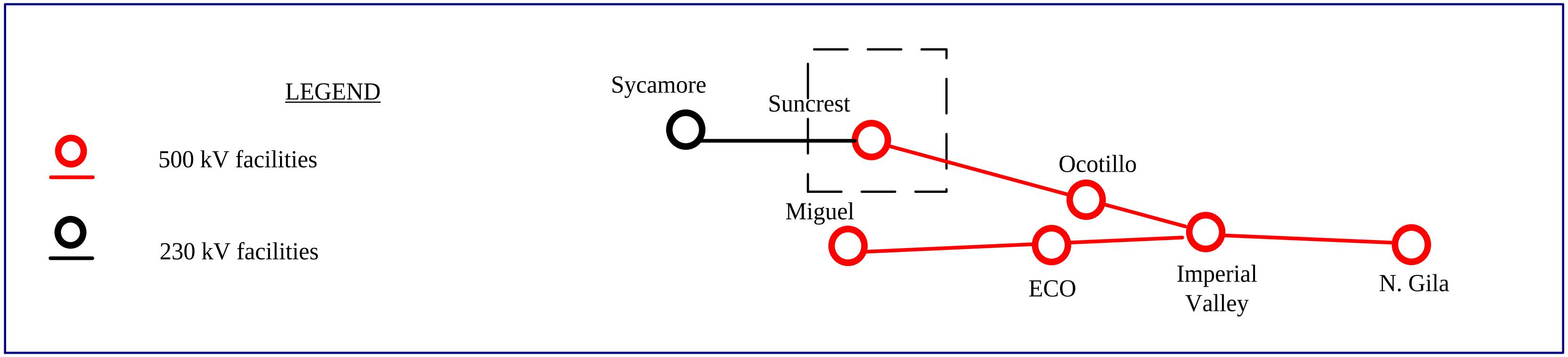
Cost: $70 million

Other Considered Alternatives:

- New 500kV line from Eldorado area to Lugo area (> $500 million)

Expected In-Service: 2016

Suncrest Dynamic Reactive Power Device



- **Needs**: To provide continuous reactive power response in order to mitigate voltage dip violation at Suncrest 230 kV and 500 kV buses following system disturbances
- **Project Scope**: Install a +300/-100 MVAr dynamic reactive power device with POI at Suncrest 230 kV bus. It needs to be one of the following types of device: SVC (Static VAR Compensator), STATCOM (Static Synchronous Compensator), or Synchronous Condenser
- **Cost**: $50M to $75M
- **Expected in service date**: 2017

Imperial Valley Deliverability Constraint

- Based on previous studies, 1715 MW of renewable generation could be accommodated in the Imperial zone
- With SONGS retired and Sycamore-Suncrest 230 kV lines de-rated, Imperial zone renewables are not deliverable
  - Overload on Otay Mesa-Tijuana 230 kV following N-1 outages of IV-ECO or ECO-Miguel 500 kV lines
    - Requires SPS to trip IV generation and CFE cross-trip, Sycamore-Suncrest 230 kV lines overload after cross-trip
  - Installing a flow control device on CFE system provides deliverability for approximately 450 MW

Imperial Valley Deliverability Constraint – con't

- Restoring original Sycamore-Suncrest 230 kV line emergency ratings increases deliverability to 800 MW
  - Alternative is to add a new Suncrest-Los Coches 230 kV line, this may require upgrading IV-OCO 500 kV series capacitor and terminal equipment
- With the flow control device and assuming Sycamore-Suncrest 230 kV overloads have been mitigated, the next limiting constraint is on the IV-ECO and ECO-Miguel 500 kV lines following N-1 outages of IV-OCO and OCO-Suncrest 500 kV lines
  - SPS to trip 1150 MW of IV generation is not sufficient
  - Adding Delany-Colorado River 500 kV line increases deliverability to approximately 1000 MW

Further Analysis in the 2014/15 TPP is needed for the Imperial Valley Deliverability constraint

- It is expected that a major transmission upgrade would be needed to ensure deliverability of the entire portfolio amount in the Imperial area
- Further study is needed in the next planning cycle to develop the most cost effective comprehensive transmission plan for this area
- Next steps will be coordinated with CPUC and CEC for the 2014/2015 plan

Economic Planning Studies

Draft 2013-2014 ISO Transmission Plan Stakeholder Meeting

Binaya Shrestha and Luba Kravchuk
Sr. Regional Transmission Engineers
February 12, 2014

Steps of economic planning studies

Economic planning study requests

Economic planning studies

We are here

- (Step 1) Unified study assumptions
- (Step 2) Development of simulation model
- (Step 3) Preliminary study results
- (Step 4) Final study results

1st stakeholder meeting
Feb 28, 2013
Study assumptions

2nd stakeholder meeting
Sep 25-26, 2013
Reliability studies

3rd stakeholder meeting
Dec 20-21 2013
Policy and economic studies

4th stakeholder meeting
Feb 12, 2014
ISO Transmission Plan

Phase 1
Study plan

Phase 2
Technical studies, project recommendations and ISO approval

Transmission Plan

Phase 3
Competitive solicitation

CAISO 2013-2014
Transmission Planning Process (TPP)

Assumptions for engineering analysis

Category	Type	TP2013-2014	TP2012-2013
Load	In-state load	CEC 2011 IEPR (2018, 2023) with AAEE	CEC 2011 IEPR (2017, 2022) w/o AAEE
	Out-of-state load	LRS 2012 data (2018, 2023)	LRS 2012 data (2017, 2022)
	Load profiles	TEPPC profiles	Same
	Load distribution	Four seasonal load distribution patterns	Same
Generation	RPS	CPUC/CEC 2013 RPS portfolios	CPUC/CEC 2012 RPS portfolios
	Generation profiles	TEPPC profiles plus CPUC profiles for DG	Same
	Hydro and pumps	TEPPC hydro data based on year 2005 pattern	Same
	Coal	Coal retirements in Southwest	Status quo
	Nuclear	SONGS retirement	SONGS available
	Once-Thru-Cooling	Based on ISO TP2012 nuke sensitivity study results	ISO 2012 OTC assumptions
	Natural gas units	ISO 2012 Unified Study Assumptions	Almost the same
	Natural gas prices	CEC 2013 IEPR Preliminary – NAMGas (2018, 2023)	E3 2010 MPR prices (2017, 2022)
	Other fuel prices	TEPPC fuel prices	Same
	GHG prices	CEC 2013 IEPR Preliminary – CO_2 prices	CPUC 2011 MPR – CO_2 prices
Transmission	Reliability upgrades	Plus to-be-approved projects in this planning cycle	Already-approved projects
	Policy upgrades	Plus to-be-approved projects in this planning cycle	Already-approved projects
	Economic upgrades	No economically-driven upgrades	Same

▲ ▲ ▲ ▲ ▲

- Major differences
- Minor differences

Acronyms:
AAEE = Additional achievable energy efficiency
DG = Distributed generation

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Assumptions for financial analysis
Calculation of cost, i.e. revenue requirement

Item	TP2013-2014	TP2012-2013
Return on equity	11%	N/A
Discount rate (real)	7% (5% sensitivity)	N/A
O&M	2%	N/A
Property tax	2%	N/A
Inflation rate	2%	N/A
Asset depreciation horizon	50 years	N/A

Other assumptions:
Deferred tax revenue recovery
CWIP in rate base treatment

Note:
When detailed capital cash flows are not available, revenue requirement is approximately estimated from the capital cost.
The estimation is made by RR = 1.45 * CC, where the multiplier is based on estimating ISO prior experience on California IOUs.
This estimation approach is used only when project-specific analysis is not available at initial planning stage.
Actual revenue requirements are calculated based on project-specific information conducted on a case-by-case basis

Acronyms:
O&M = Operations and maintenance
CWIP = Construction work in progress
CC = Capital cost
RR = Revenue requirement
IOU = Investor-owned utilities

Assumptions for financial analysis (cont'd)

Calculation of benefits

Item	TP2013-2014	TP2012-2013
Discount rate (real)	7% (5% sensitivity)	Same
Escalation rate (real) for extrapolation of yearly benefits	0%	1%
Economic lifespan for new build of transmission facilities	50 years	Same
Economic lifespan for upgrades of existing transmission facilities	40 years	Same

Acronyms:
RA = Resource adequacy
LCR = Local capacity requirement
CC = Capital cost
RR = Revenue requirement
IOU = Investor-owned utilities

Changes since last meeting

#	Category	Change
1	Engineering analysis	Performed sensitivity study modeling major reliability and policy-driven upgrades identified in this 2013/2014 TPP cycle.
2	Financial analysis	5% discount rate sensitivity for projects considered for approval.

Major upgrades modeled for sensitivity study

- Upgrade Lugo-Mohave series capacitors
- Mesa 500 kV loop-in
- CFE phase shifter
- Incremental 400 MW OTC reduction

Identified congestion and high priority studies

Simulated congestion in the ISO-controlled grid

#	Area	Congested transmission element	Congestion duration (hours)		Average congestion cost ($M)
			Year 2018	Year 2023	
1	PG&E and SCE	Path 26 (Midway – Vincent) ❶ ❷ ❸ ❹ ❺	878	545	6.890
2	SCE	North of Lugo (Kramer – Lugo 230 kV)	623	85	6.148
3	SCE	North of Lugo (Inyo 115 kV)	769	1,252	0.734
4	SCE and SDG&E	SCIT limits ❶ ❷ ❸ ❹ ❺	23	2	0.647
5	SCE	LA metro area	77	-	0.323
6	PG&E and PacifiCorp	Path 25 (PacifiCorp/PG&E 115 kV Interconnection) ❷	448	651	0.117
7	SCE	Mirage – Devers area ❶ ❷ ❸ ❹ ❺	83	7	0.080
8	SCE	Vincent 500 kV transformer ❶	6	4	0.037
9	PG&E	Greater Bay Area (GBA)	4	16	0.026
10	BPA and PG&E	Path 66 (COI) ❷	3	-	0.002

Ranked by severity

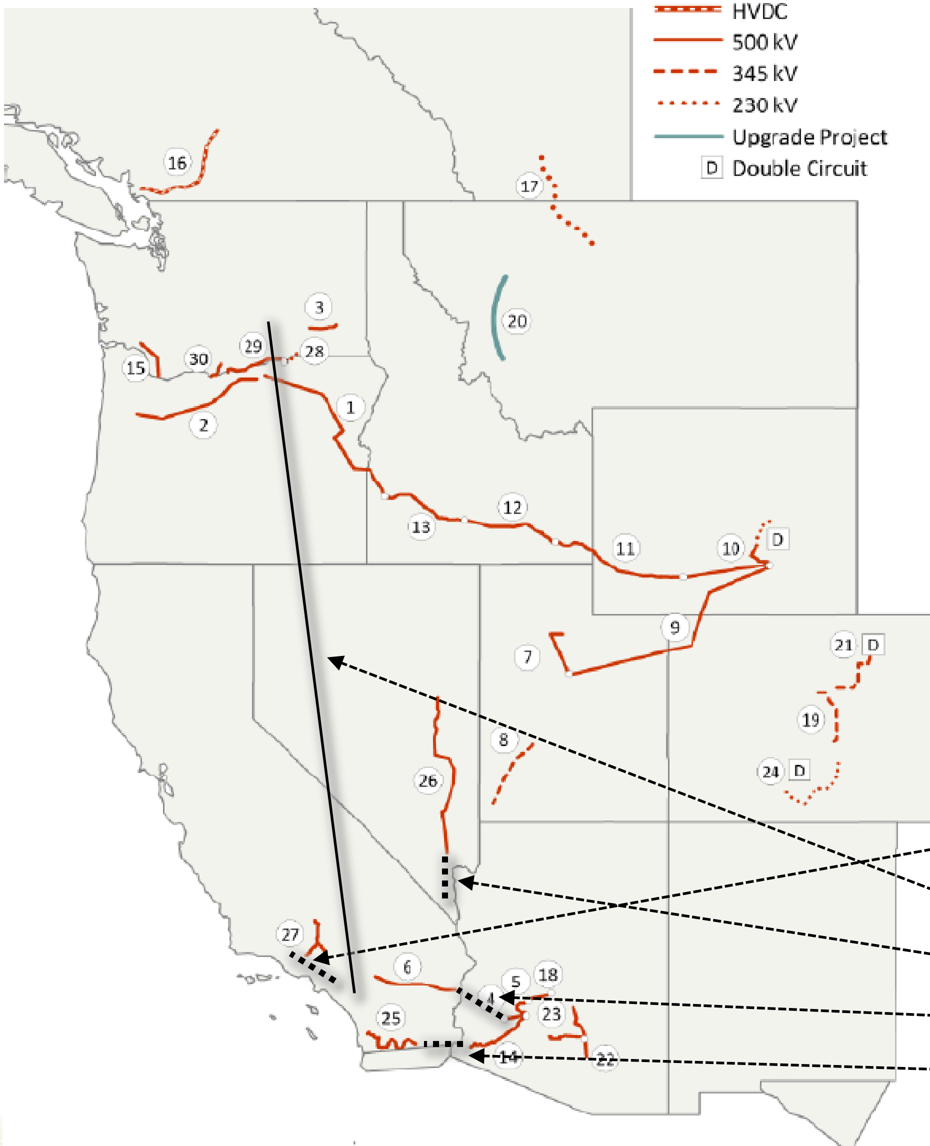
High priority studies

	Study ID	Study subject
❶	P26-3	Path 26 Northern - Southern CA
❷	NWC-1	PDCI upgrade
❸	SWC-1	Harry Allen – Eldorado 500 kV line
❹	SWC-2	Delaney – Colorado River 500 kV line
❺	SWC-3	North Gila – Imperial Valley 500 kV line #2

Note: With item #3, the congestion in the Control - Inyo – Kramer 115 kV system affects the geothermal generation in the area. Other than item #3, all other congestion does not affect renewables

Subjects of economic planning studies

In a big picture



The red lines represent approved new transmission projects that are modeled in the TEPPC database

- 26 One Nevada Line, aka. ON-Line, (2013)
- 6 Colorado River – Valley line #2 (2013)
- 27 Tehachapi Renewable Transmission Project (2012-2013)
- 25 Sunrise Powerlink (2012)
- 14 Hassayampa – North Gila 500 kV line #2 (2015)

Five high-priority studies

#	ID	Proposed upgrade	Mileage
1	P26-3	Midway – Vincent 500 kV line #4	110
2	NWC-1	PDCI upgrade by 500 MW	-
3	SWC-1	Harry Allen – Eldorado 500 kV line	60
4	SWC-2	Delaney – Colorado River 500 kV line	110
5	SWC-3	North Gila – Imperial Valley 500 kV line #2	80

Source of the underlying map: "Common Case Transmission Assumptions", WECC SPG Coordination Group, February 2012

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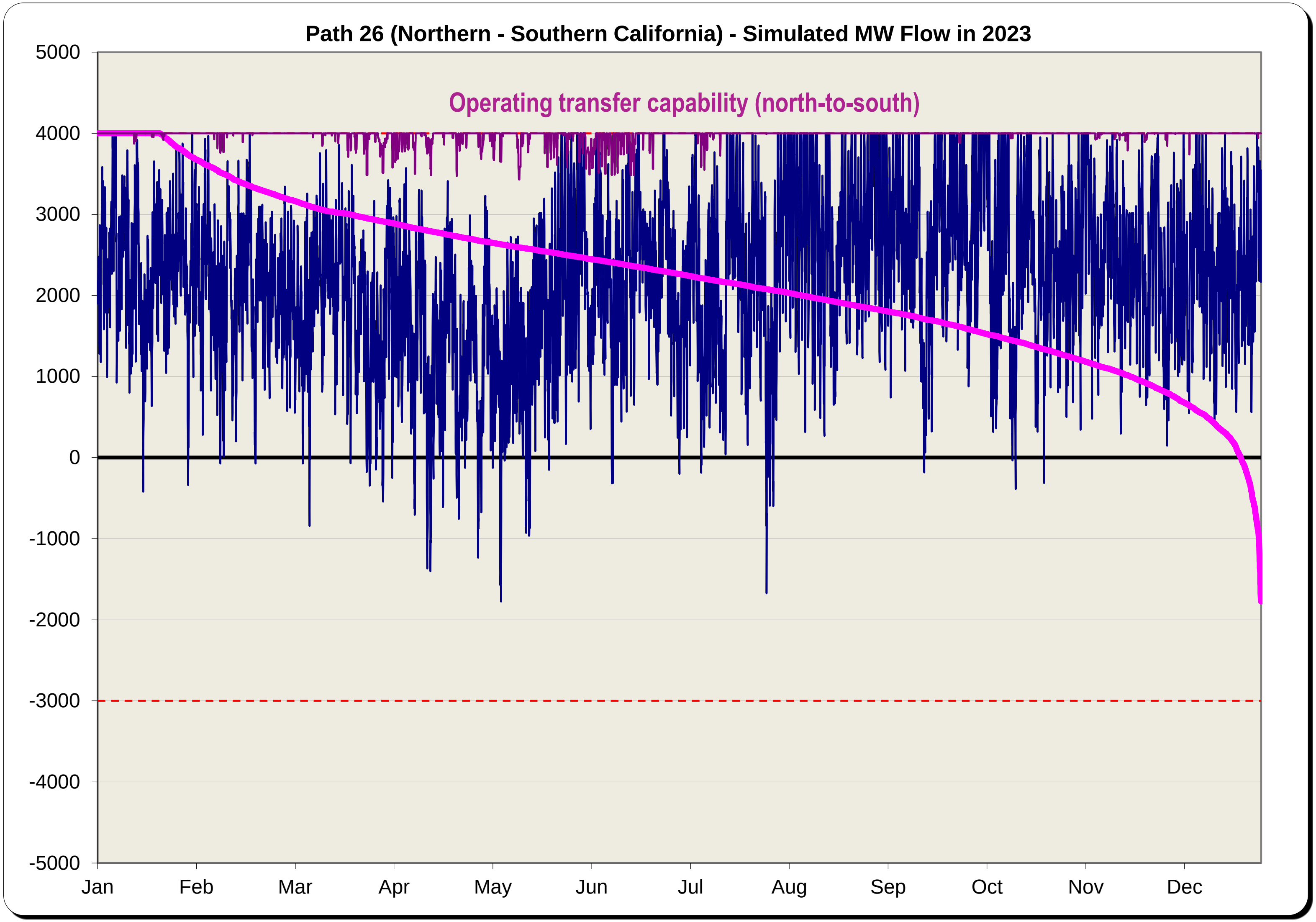
Simulated power flow on Path 26



Effects of congestion relief

With addition of the Midway – Vincent 500 kV line #4

2018:

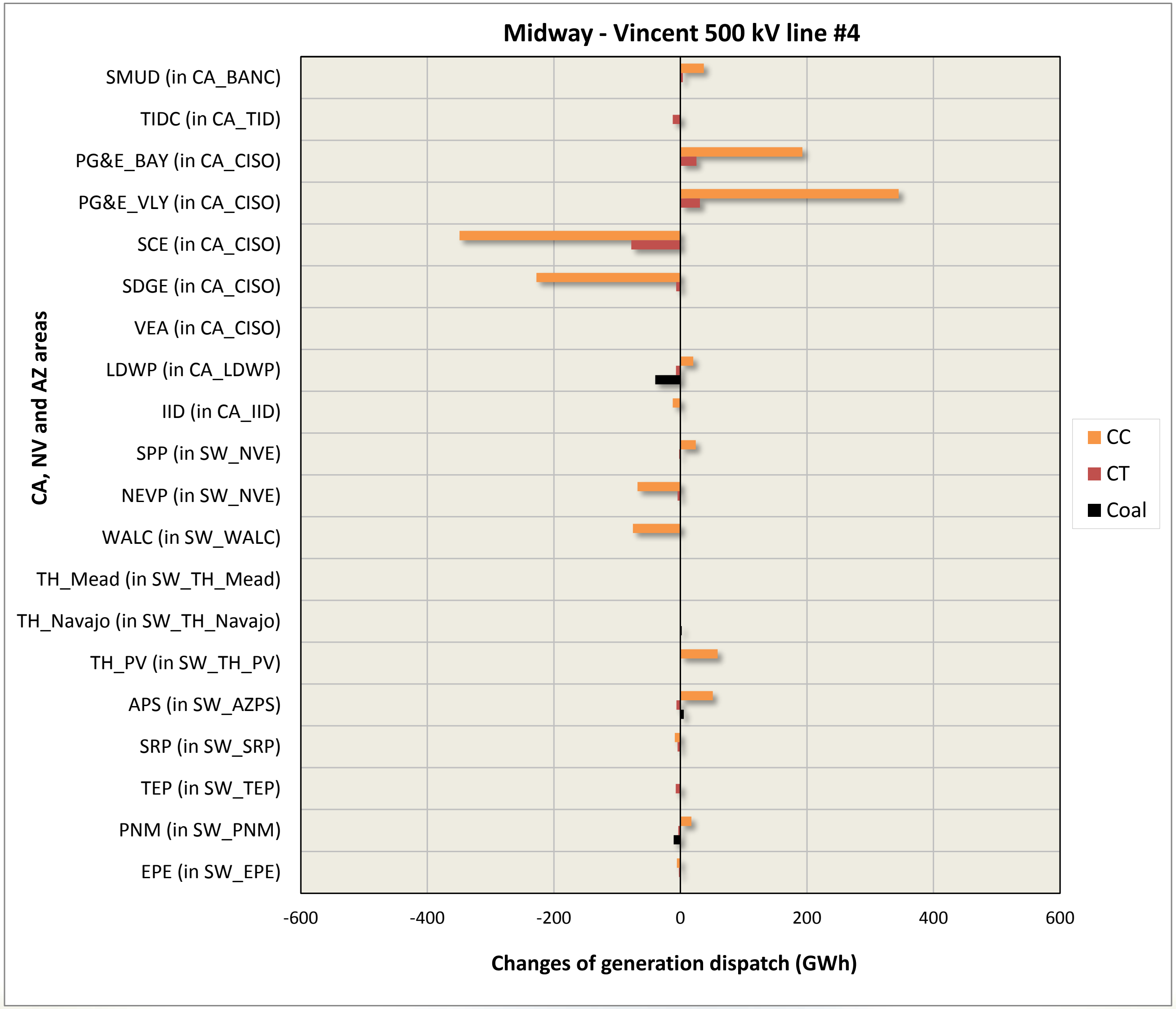
Transmission facility	Utility	Before	After	Change
Path 25 (PacifiCorp/PG&E 115 kV)	PacifiCorp – PG&E	488	571	+83
Kramer – Lugo 230 kV line #1 and #2	SCE	623	537	-86
Path 26 (Midway – Vincent)	PG&E – SCE	878	158	-720
Vincent 500 kV transformer	SCE	6	106	+100

2023:

Transmission facility	Utility	Before	After	Change
Path 25 (PacifiCorp/PG&E 115 kV)	PacifiCorp – PG&E	651	687	+36
Kramer – Lugo 230 kV line #1 and #2	SCE	85	76	-9
Path 26 (Midway – Vincent)	PG&E – SCE	545	100	-445
Vincent 500 kV transformer	SCE	4	46	+42

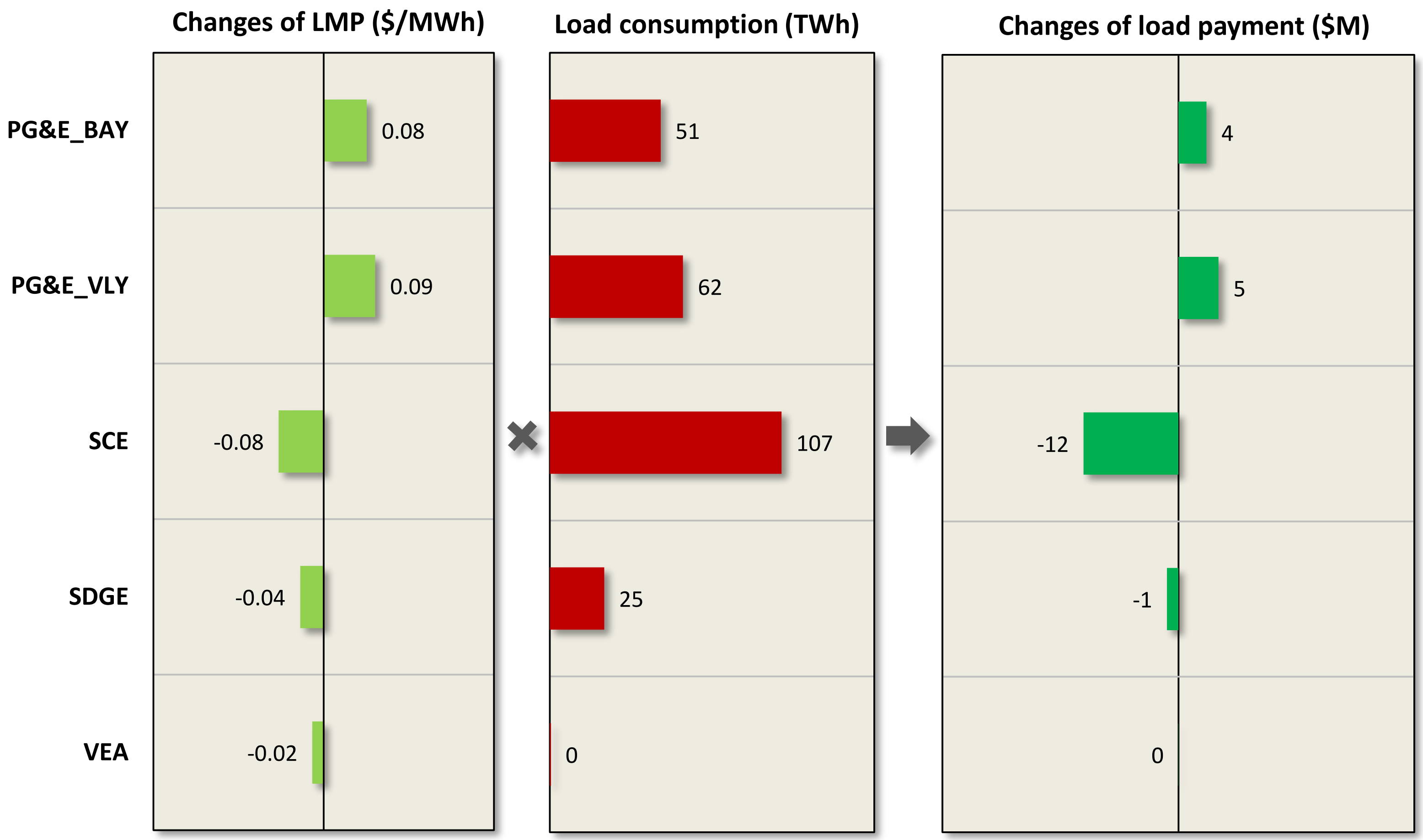
Incremental changes of generation dispatch

With addition of the Midway – Vincent 500 kV line #4



Load payment reductions in the ISO-controlled grid

With addition of the Midway – Vincent 500 kV line #4



Simulation year 2023

The "Changes of LMP ($/MWh)" is the difference of annual averages

Determination of yearly production benefits

With addition of the Midway – Vincent 500 kV line #4

Year	Production		Part 1		Part 2
2018	-$4M	=	-$4M	+	$0M
2023	$4M	=	$4M	+	$0M

Where:

Part 1		Consumer	Producer	Transmission
-$4M	=	-$4M	$7M	-$7M
$4M	=	$4M	$5M	-$5M

Computed by GridView production simulation for 8,760 hours in each study year by comparison of "pre-project" and "post-project" cases

Part 2		Losses reduction benefit
$0M	=	~0 MW * 8760 hours * $40.15/MWh

Losses reduction estimated

Average LMP in 2023 in SCE area

Determination of yearly capacity benefits

With addition of the Midway – Vincent 500 kV line #4

Capacity benefit is determined to be zero:

1. **System RA benefit is not applicable because this line is within the ISO**
2. **LCR benefit is not applicable**

Economic assessment for “P26-3”

Midway – Vincent 500 kV line #4

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	(4)	(2)	(1)	1	2	4	4	4	…
Capacity benefit	-	-	-	-	-	-	-	-	…
Total yearly benefit	(4)	(2)	(1)	1	2	4	4	4	…

Pushing off operation year →	2018	2019	2020	2021	2022	2023
Total benefit Sum of discounted yearly benefits	35	41	47	51	54	55
Total cost Total revenue requirement	1,595	1,595	1,595	1,595	1,595	1,595

1,100	Capital cost

Net benefit	(1,560)	(1,554)	(1,548)	(1,544)	(1,541)	(1,540)
Benefit-cost ratio	0.02	0.03	0.03	0.03	0.03	0.03

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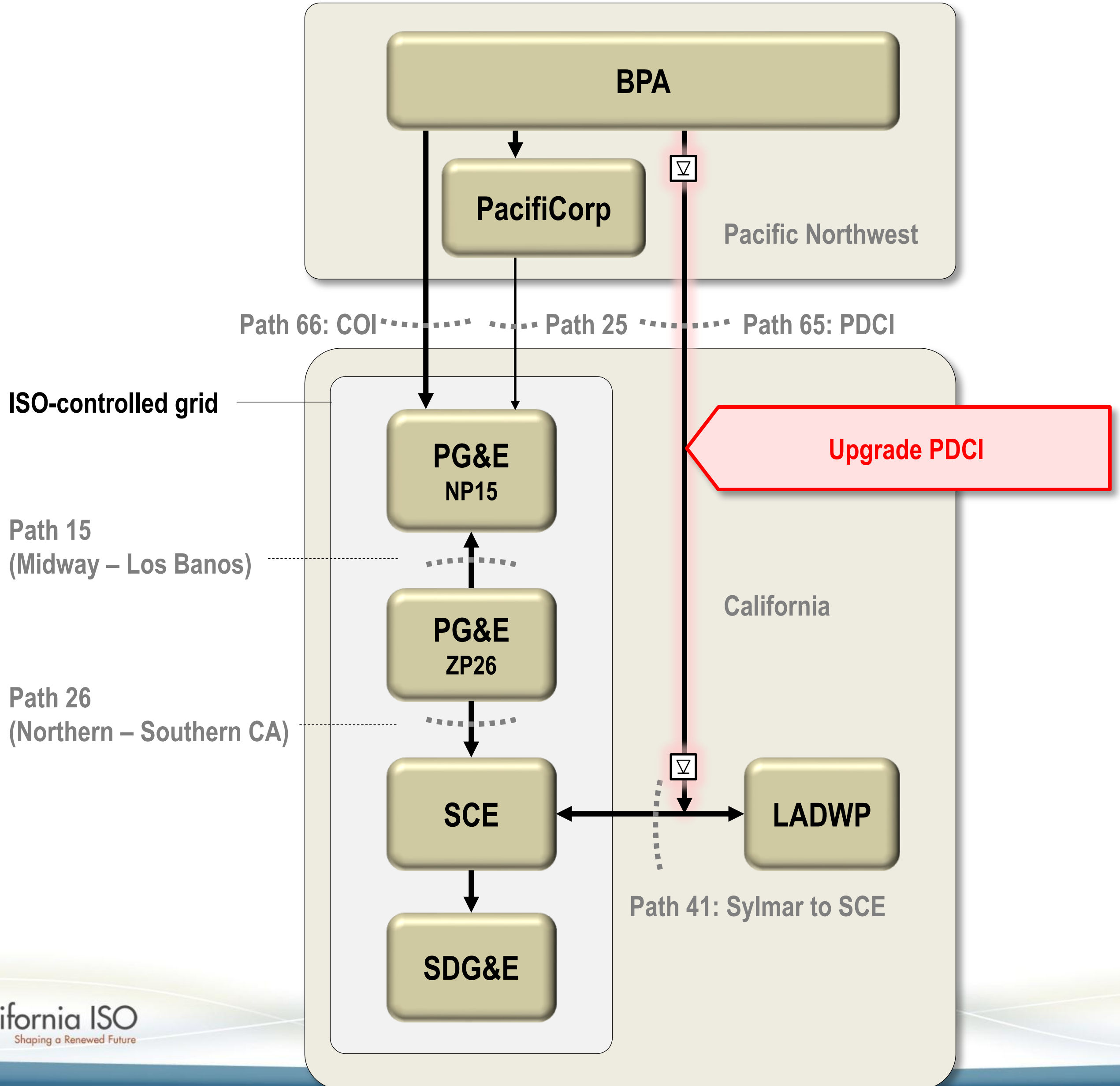
Pacific Northwest – California (NWC) area

PDCI upgrade



California ISO
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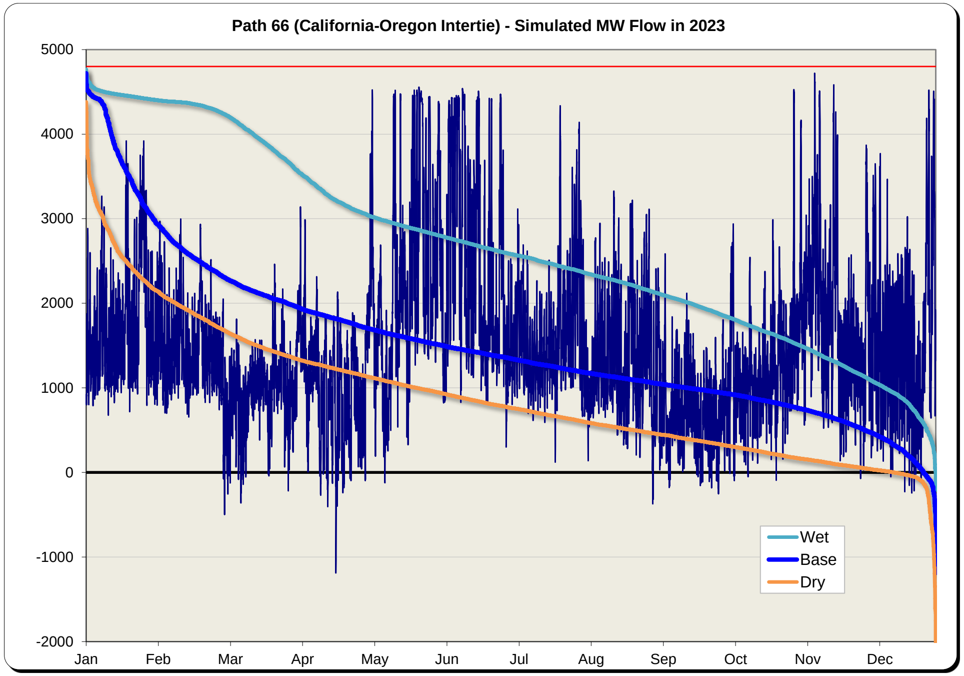
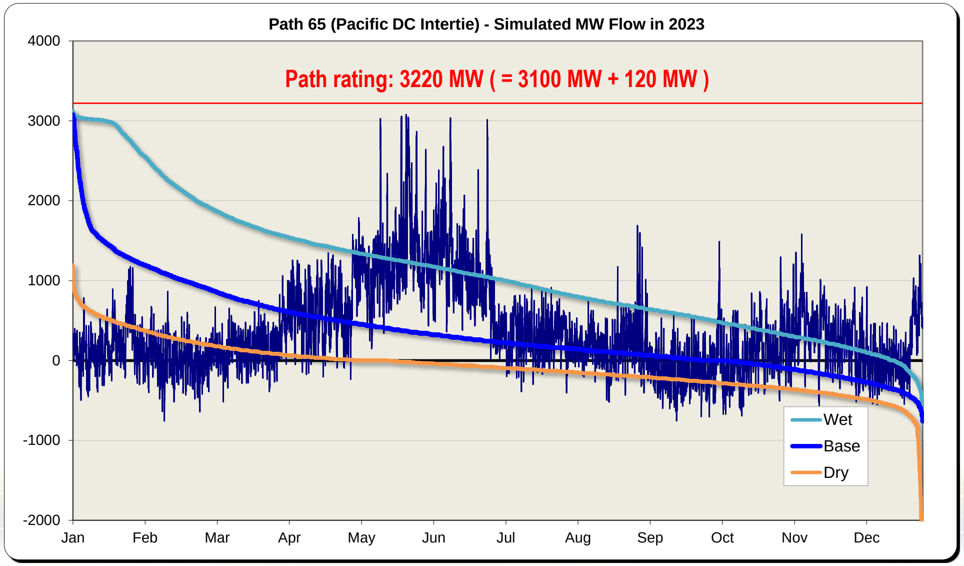
Simulated power flow on Path 66 (COI) and Path 65 (PDCI)





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Effects of congestion relief

With upgrade of PDCI by 500 MW rating increase

2018:

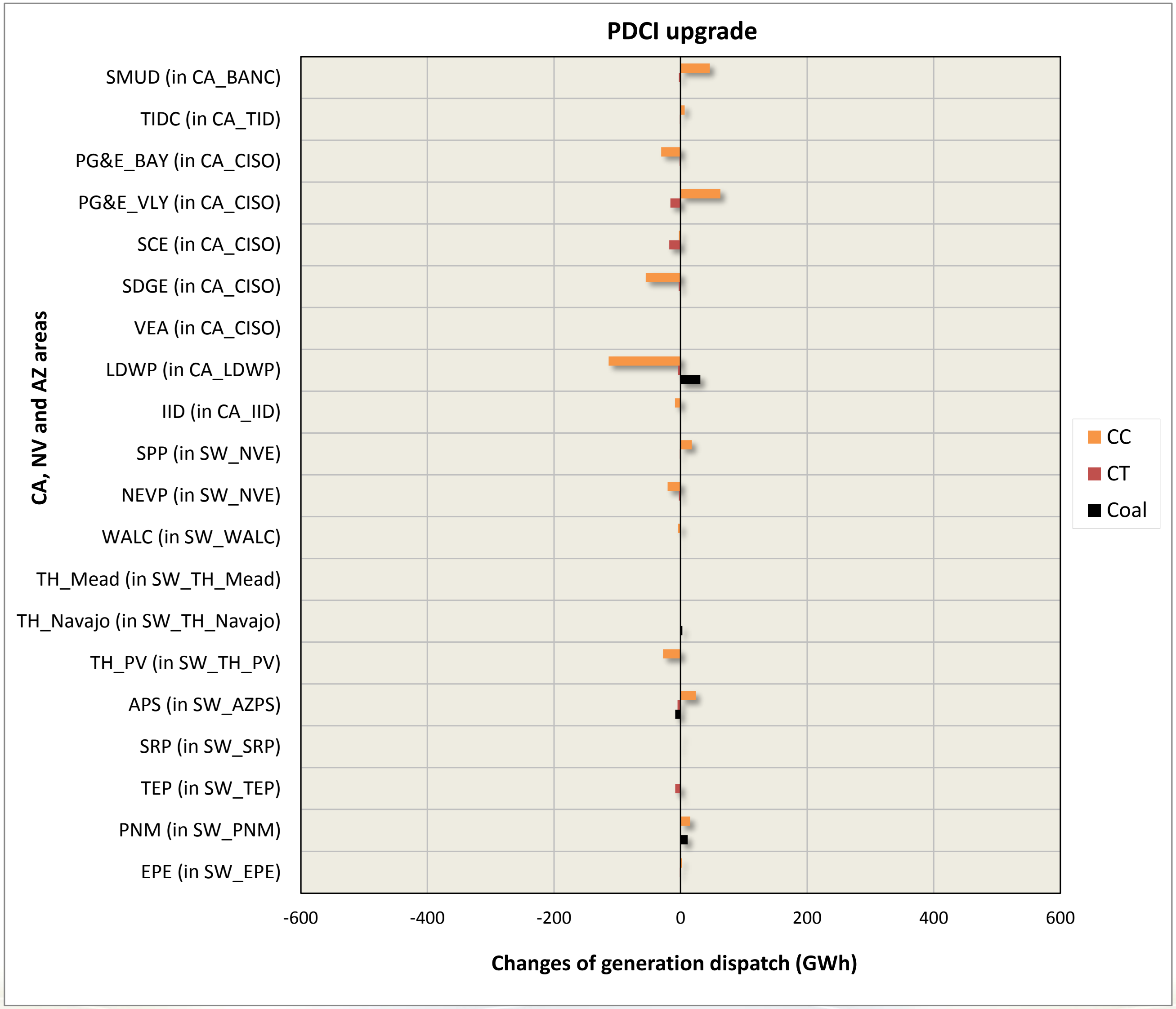
Transmission facility	Utility	Before	After	Change
Path 25 (PacifiCorp/PG&E 115 kV)	PacifiCorp – PG&E	488	477	-11
Kramer – Lugo 230 kV line #1 and #2	SCE	623	603	-20
Path 26 (Midway – Vincent)	PG&E – SCE	878	831	-47
Julian Hinds – Mirage 230 kV line	SCE	83	74	-9

2023:

Transmission facility	Utility	Before	After	Change
Path 25 (PacifiCorp/PG&E 115 kV)	PacifiCorp – PG&E	651	640	-11
Kramer – Lugo 230 kV line #1 and #2	SCE	85	90	+5
Path 26 (Midway – Vincent)	PG&E – SCE	545	544	-1
Julian Hinds – Mirage 230 kV line	SCE	7	5	-2

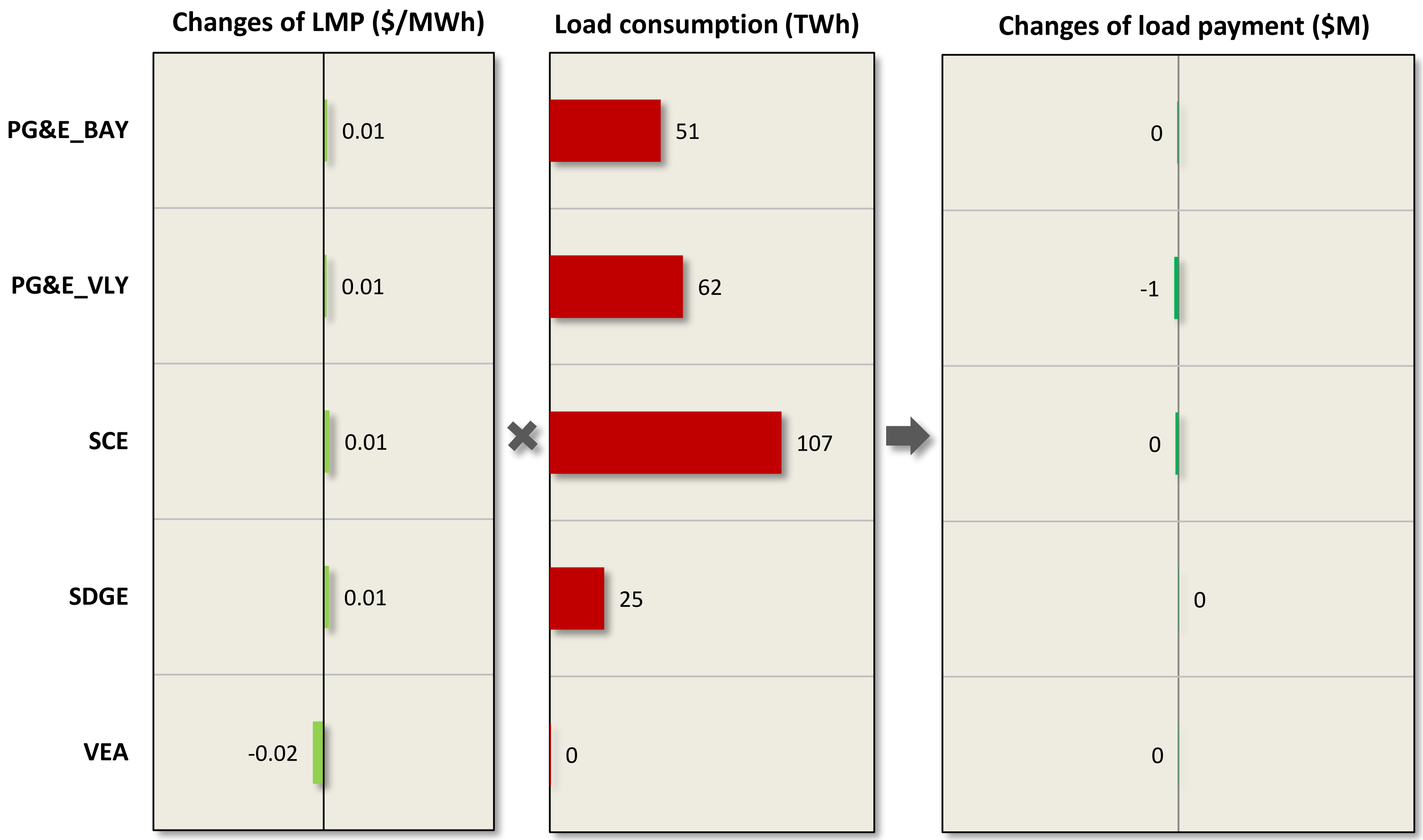
Incremental changes of generation dispatch

With upgrade of PDCI by 500 MW rating increase



Load payment reductions in the ISO-controlled grid

With upgrade of PDCI by 500 MW rating increase



Simulation year 2023

The “Changes of LMP ($/MWh)” is the difference of annual averages

Determination of yearly production benefits

With upgrade of PDCI by 500 MW rating increase

Year	Production		Part 1		Part 2
2018	$7M	=	$7M	+	$0M
2023	$3M	=	$3M	+	$0M

Where:

Part 1		Consumer	Producer	Transmission
$7M	=	$9M	-$1M	-$1M
$3M	=	$1M	$2M	$0M

Computed by GridView production simulation for 8,760 hours in each study year by comparison of "pre-project" and "post-project" cases

Part 2		Losses reduction benefit
$0M	=	~0 MW * 8760 hours * $40.15/MWh

Losses reduction estimated

Average LMP in 2023 in SCE area

California ISO
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Determination of yearly capacity benefits

With upgrade of PDCI by 500 MW rating increase

Capacity benefit is estimated to be zero:

1. **System RA benefit is zero because of downstream bottleneck**
2. **LCR benefit is zero because the PDCI southern terminus is outside the LCR boundary for the LA Basin**

Cost-benefit analysis for "NWC-1"

Upgrade PDCI by 500 MW rating increase

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	7	6	5	4	4	3	3	3	…
Capacity benefit	-	-	-	-	-	-	-	-	…
Total yearly benefit	7	6	5	4	4	3	3	3	…

Assumed operation year →	2018
Total benefit Sum of discounted yearly benefits	50
Total cost Total revenue requirement	435

300	Capital cost

Net benefit	(385)
Benefit-cost ratio	0.12

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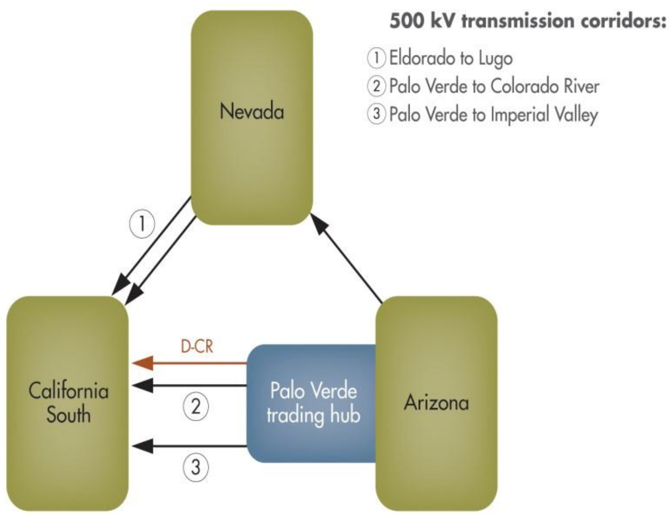
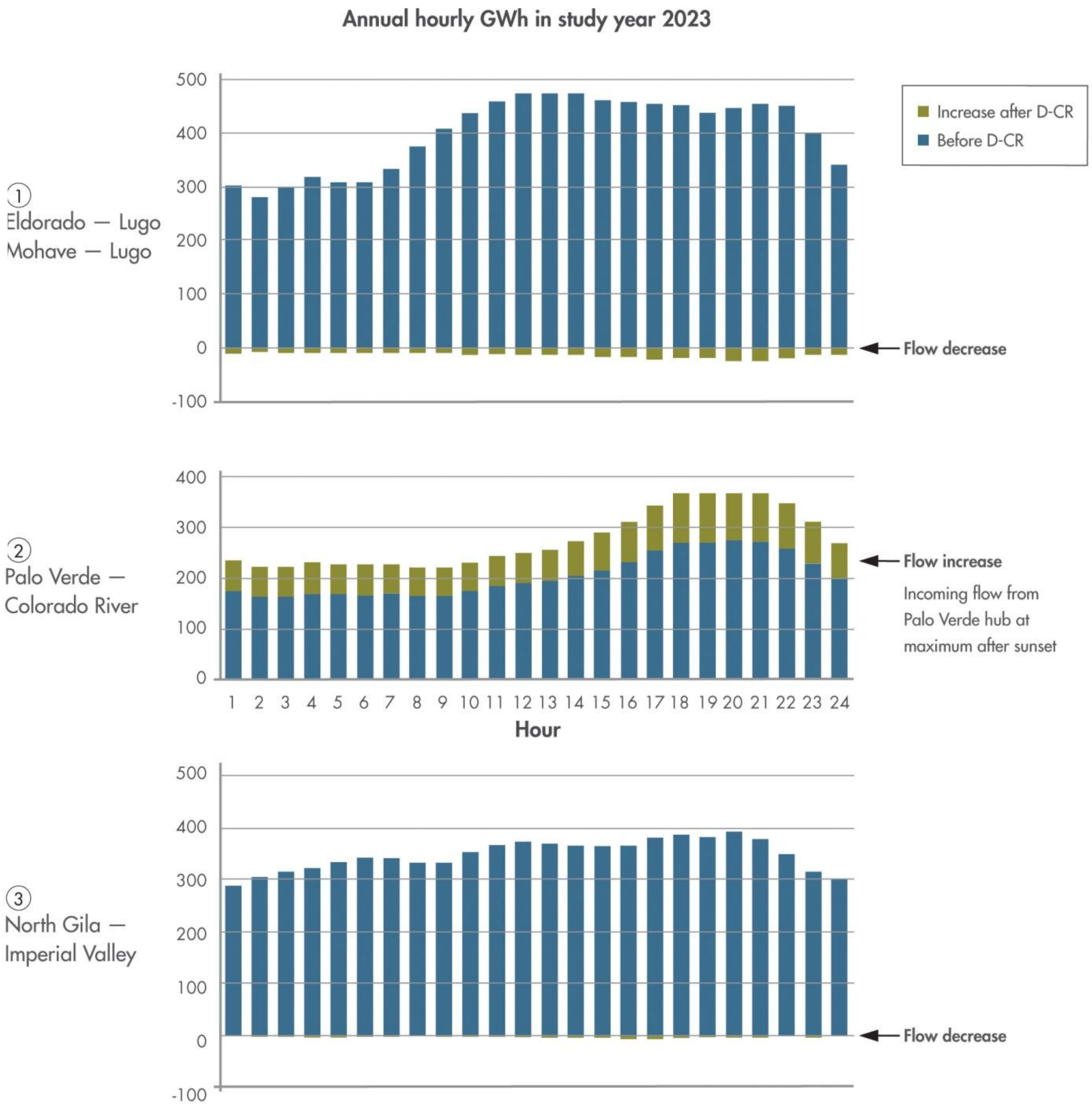
Imports from Southwest to Southern CA

Before and after the Delaney – Colorado River 500 kV line



The Palo Verde trading hub has the largest concentration of efficient generation in the Western Interconnection



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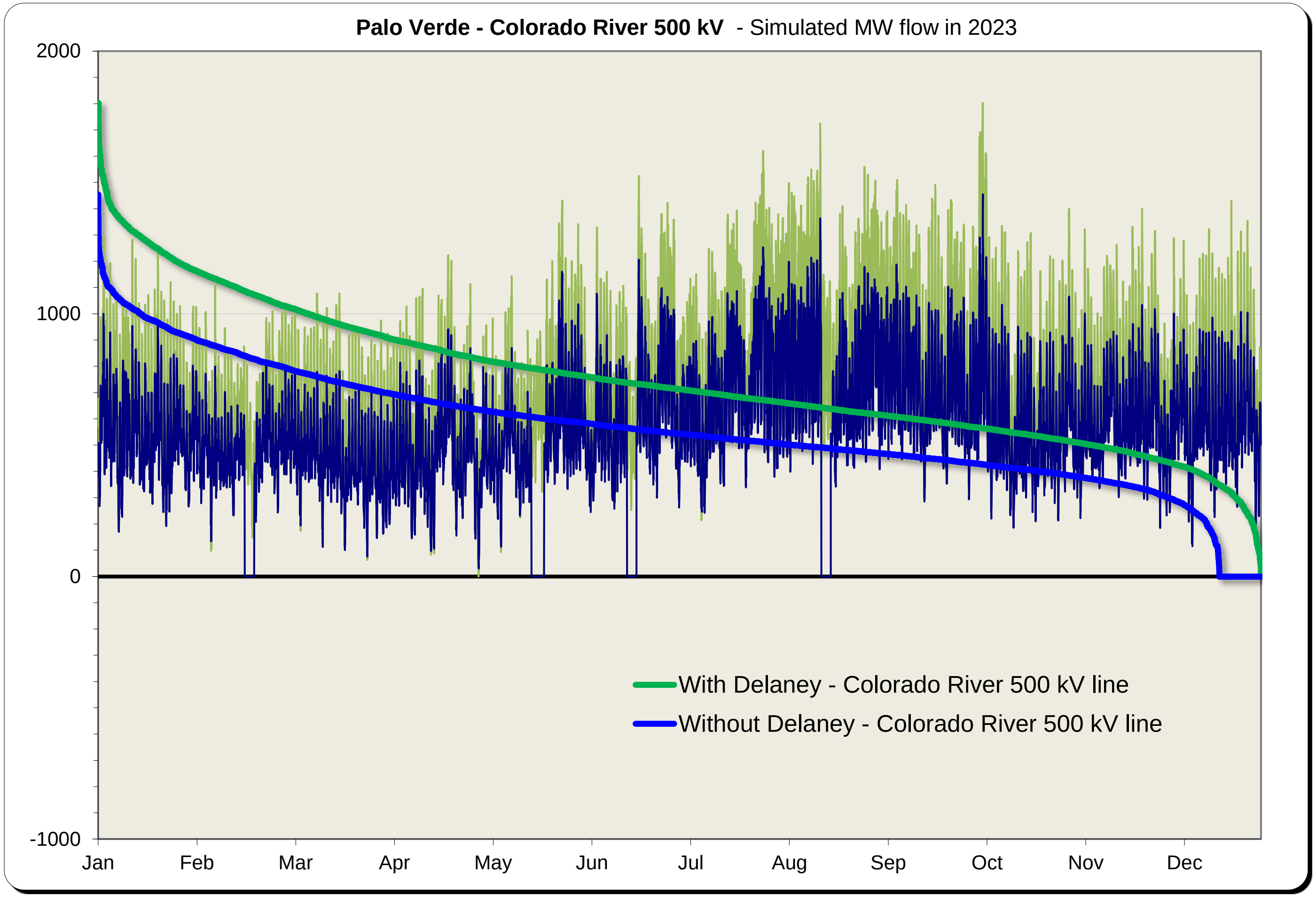
Line flow from Palo Verde to Colorado River

Before and after the Delaney – Colorado River 500 kV line



The Delaney – Colorado River 500 kV line allows SCE area to:

1. Have more efficient access to the Palo Verde trading hub

2. Have uninterrupted access to the Palo Verde hub under L-1 conditions

3. Receive 30% more dispatched energy via this transmission corridor

Effects of congestion relief

With addition of the Delaney – Colorado River 500 kV line

2018:

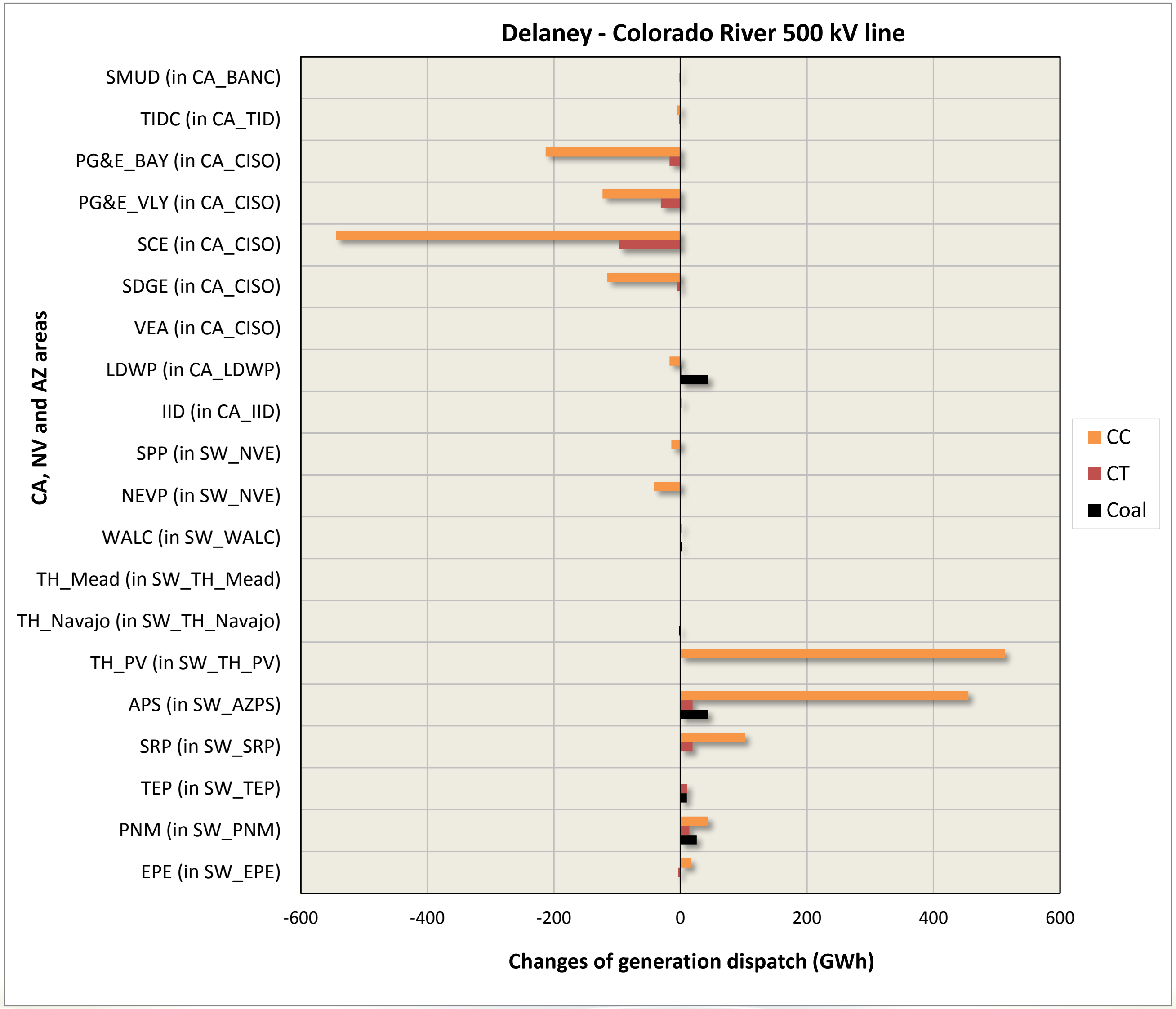
Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,366	1,366	0
Perkins – Mead 230 kV line	SRP/APS – WAPA	73	39	-34
Path 26 (Midway – Vincent)	PG&E – SCE	878	768	-110
Julian Hinds – Mirage 230 kV line	SCE	83	2	-81

2023:

Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,526	1,519	-7
Perkins – Mead 230 kV line	SRP/APS – WAPA	13	9	-4
Path 26 (Midway – Vincent)	PG&E – SCE	545	492	-53
Julian Hinds – Mirage 230 kV line	SCE	7	0	-7

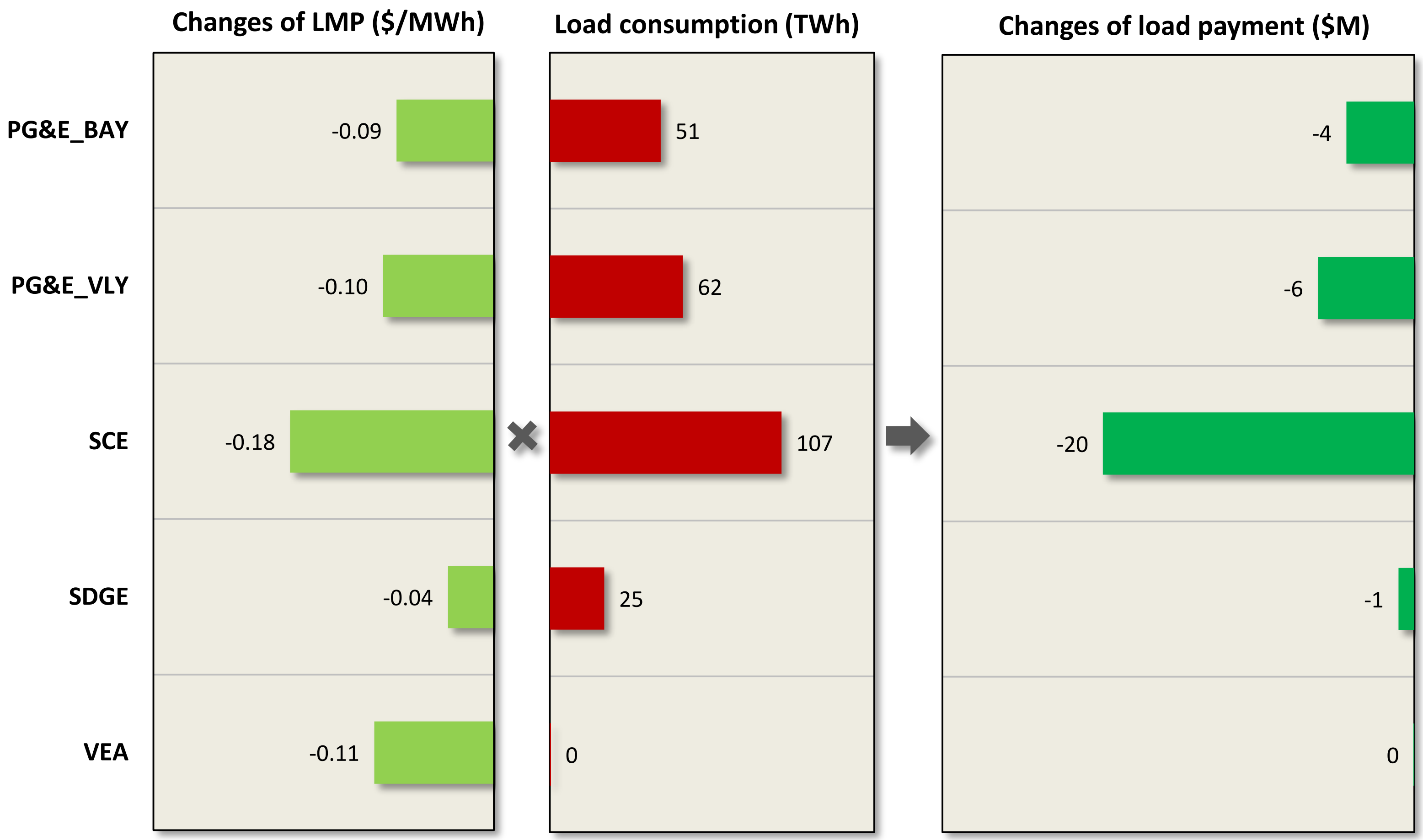
Incremental changes of generation dispatch

With addition of the Delaney – Colorado River 500 kV line



Load payment reductions in the ISO-controlled grid

With addition of the Delaney – Colorado River 500 kV line



Simulation year 2023

The “Changes of LMP ($/MWh)” is the difference of annual averages

Determination of yearly production benefits

With addition of the Delaney – Colorado River 500 kV line

Year	Production		Part 1		Part 2
2018	$30M	=	$30M	+	$1M
2023	$25M	=	$25M	+	$1M

Where:

Part 1		Consumer	Producer	Transmission
$30M	=	$38M	-$5M	-$3M
$25M	=	$31M	-$4M	-$2M

Computed by GridView production simulation for 8,760 hours in each study year by comparison of "pre-project" and "post-project" cases

Part 2		Losses reduction benefit
$1M	=	3.62 MW * 8760 hours * $40.15/MWh

Losses reduction calculated by PSLF power flow

Average LMP in 2023 in SCE area

Determination of yearly capacity benefits

With addition of the Delaney – Colorado River 500 kV line

Year	System RA benefit 200 MW	System RA benefit 300 MW
2018	0	0
2019	0	0
2020	$20M	$30M
2021	$18M	$26M
2022	$15M	$23M
2023	$13M	$20M
2024	$11M	$16M
2025	$9M	$13M

See the next slide for further details

Note:
The above capacity benefit is system RA benefit. LCR benefit is not applicable for this line.

Determination of yearly capacity benefits (cont'd)

With addition of the Delaney – Colorado River 500 kV line

Assumptions for capacity benefits:

- **Delaney – Colorado River transmission capacity is available in 2020 (internal limitations until then)**
- **California is resource deficit prior to 2020**
- **Desert Southwest becomes resource deficit in 2025**
- **Aero-derivative Combustion Turbines (CT) are the current and future choice of thermal peak capacity**
- **Aero CTs are more economical to build and operate in AZ ($164/kw-yr) compared to CA ($208/kw-yr)**

Cost-benefit analysis for "SWC-2"

Delaney – Colorado River 500 kV line (200 MW Capacity Benefit)

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	31	30	29	28	27	26	26	26	…
Capacity benefit (200 MW)	-	-	20	18	15	13	11	9	…
Total yearly benefit	31	30	49	46	42	39	37	35	…

Assumed operation year →	2020
Total benefits Sum of discounted yearly benefits	516
Total costs Total revenue requirement	498

325	Build the new line
20	Loop in the existing line
345	**Capital costs** Sum of the two cost items

Net benefit	18
Benefit-cost ratio	1.04

Cost-benefit analysis for “SWC-2”

Delaney – Colorado River 500 kV line (300 MW Capacity Benefit)

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	31	30	29	28	27	26	26	26	…
Capacity benefit (300 MW)	-	-	30	26	23	20	16	13	…
Total yearly benefit	31	30	59	54	50	46	39	39	…

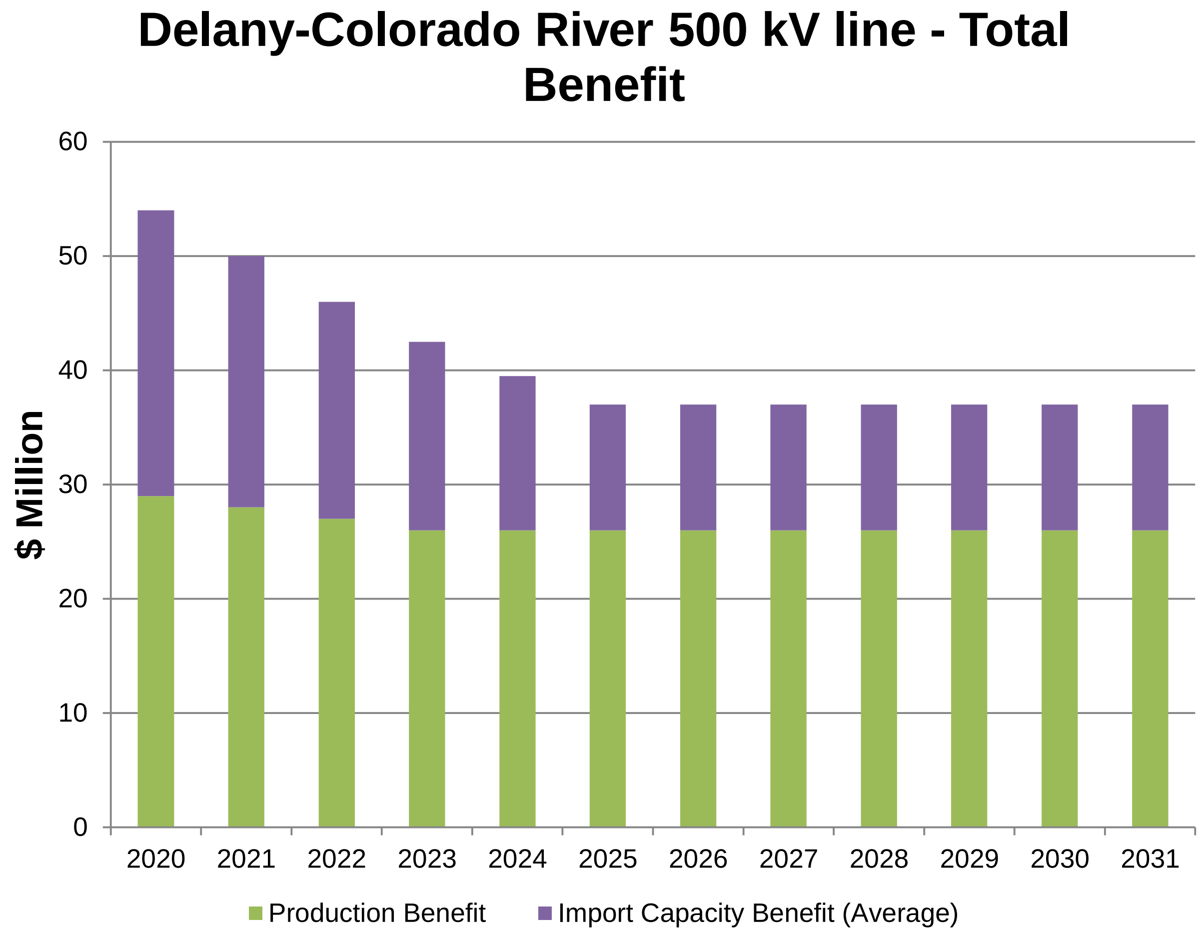
Assumed operation year →	2020
Total benefits Sum of discounted yearly benefits	568
Total costs Total revenue requirement	498

325	Build the new line
20	Loop in the existing line
345	**Capital costs** Sum of the two cost items

Net benefit	88
Benefit-cost ratio	1.18

Cost-benefit analysis for “SWC-2”

Delaney – Colorado River 500 kV line
Production Benefit and Average Capacity Benefit



Cost-benefit analysis for "SWC-2"

Delaney – Colorado River 500 kV line
5% Discount Rate Sensitivity

200 MW Incremental Import Capacity

Assumed operation year →	2020
Total benefits Sum of discounted yearly benefits	673
Total costs Total revenue requirement	498

Net benefit	75
Benefit-cost ratio	1.35

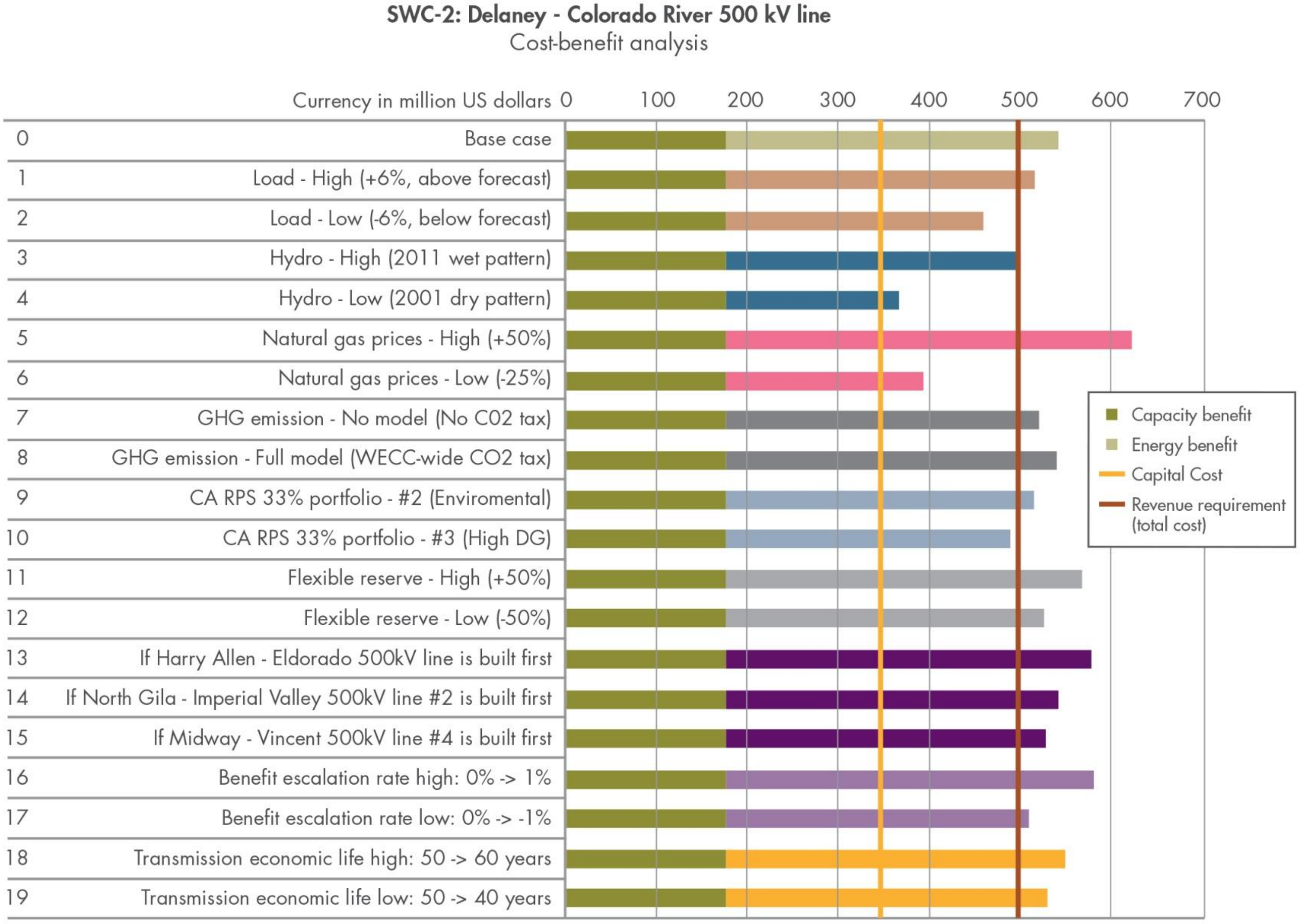
300 MW Incremental Import Capacity

Assumed operation year →	2020
Total benefits Sum of discounted yearly benefits	762
Total costs Total revenue requirement	498

Net benefit	264
Benefit-cost ratio	1.53

Sensitivity analysis (cont'd)

Cost-benefit analysis



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Effects of congestion relief

With addition of the Harry Allen – Eldorado 500 kV line

2018:

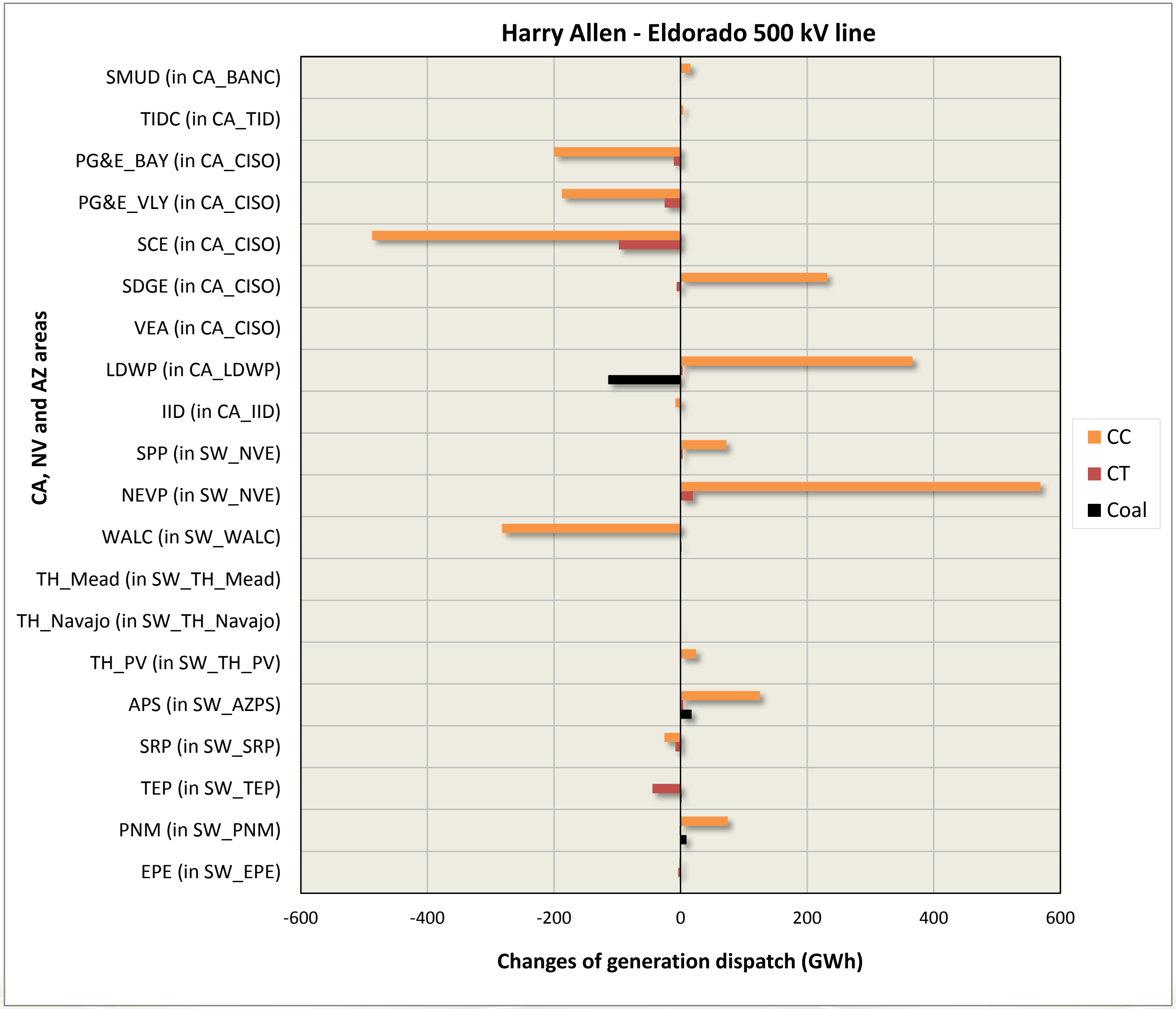
Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,366	1,064	-302
Perkins – Mead 230 kV line	SRP/APS – WAPA	73	28	-45
Path 26 (Midway – Vincent)	PG&E – SCE	878	648	-230
Julian Hinds – Mirage 230 kV line	SCE	83	79	-4

2023:

Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,526	1,194	-332
Perkins – Mead 230 kV line	SRP/APS – WAPA	13	5	-8
Path 26 (Midway – Vincent)	PG&E – SCE	545	387	-158
Julian Hinds – Mirage 230 kV line	SCE	7	14	+7

Incremental changes of generation dispatch

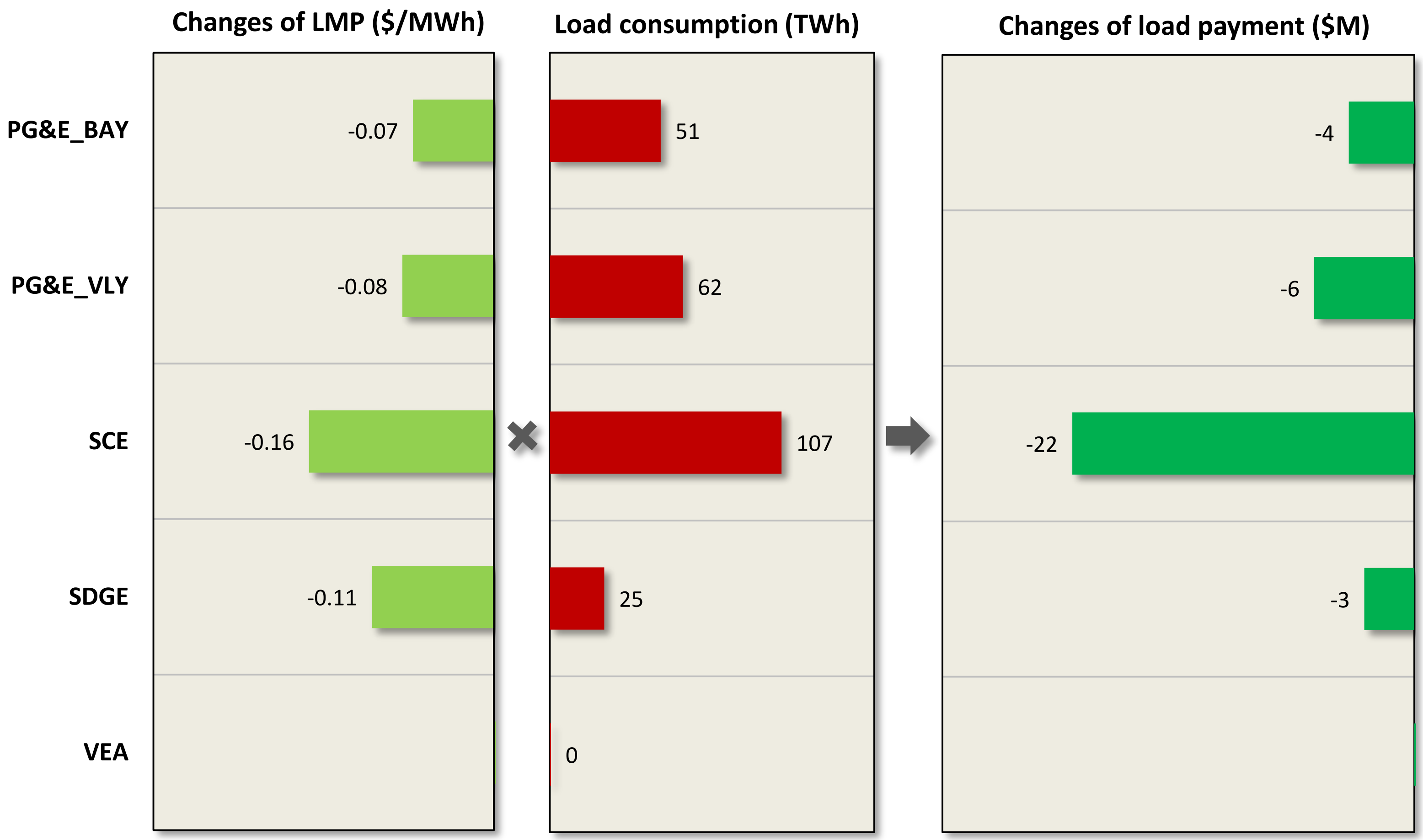
With addition of the Harry Allen – Eldorado 500 kV line



Simulation year 2023

Load payment reductions in the ISO-controlled grid

With addition of the Harry Allen – Eldorado 500 kV line



Simulation year 2023

The "Changes of LMP ($/MWh)" is the difference of annual averages

Determination of yearly production benefits

With addition of the Harry Allen – Eldorado 500 kV line

Year	Production		Part 1		Part 2
2018	-$3M	=	$3M	+	$0M
2023	$10M	=	$10M	+	$0M

Where:

Part 1		Consumer	Producer	Transmission
-$3M	=	$9M	-$2M	-$10M
$10M	=	$30M	-$4M	-$15M

Computed by GridView production simulation for 8,760 hours in each study year by comparison of "pre-project" and "post-project" cases

Part 2		Losses reduction benefit
$1M	=	~0 MW * 8760 hours * $40.15/MWh

Losses reduction estimated

Average LMP in 2023 in SCE area

California ISO
Shaping a Renewed Future

Determination of yearly capacity benefits

With addition of the Harry Allen – Eldorado 500 kV line

Year	System RA benefit
2018	0
2019	0
2020	$15M
2021	$13M
2022	$12M
2023	$10M
2024	$8M
2025	$7M
2026	$7M
2026-2069	$7M

System RA benefit calculated based on approximately 150 MW incremental import capability

Note:
The above capacity benefit is system RA benefit. LCR benefit is not applicable for this line.

Benefit-cost analysis for "SWC-1"

Harry Allen – Eldorado 500 kV line

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	(3)	0	2	5	7	10	10	10	…
Capacity benefit	0	0	15	13	12	10	8	7	…
Total yearly benefit	(3)	0	17	18	19	20	18	17	…

Assumed operation year →	2020
Total benefits Sum of discounted yearly benefits	240
Total costs Total revenue requirement	174

120	Capital costs

Net benefit	66
Benefit-cost ratio	1.38

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California ISO
Shaping a Renewed Future

Effects of congestion relief

With addition of the North Gila – Imperial Valley 500 kV line #2

2018:

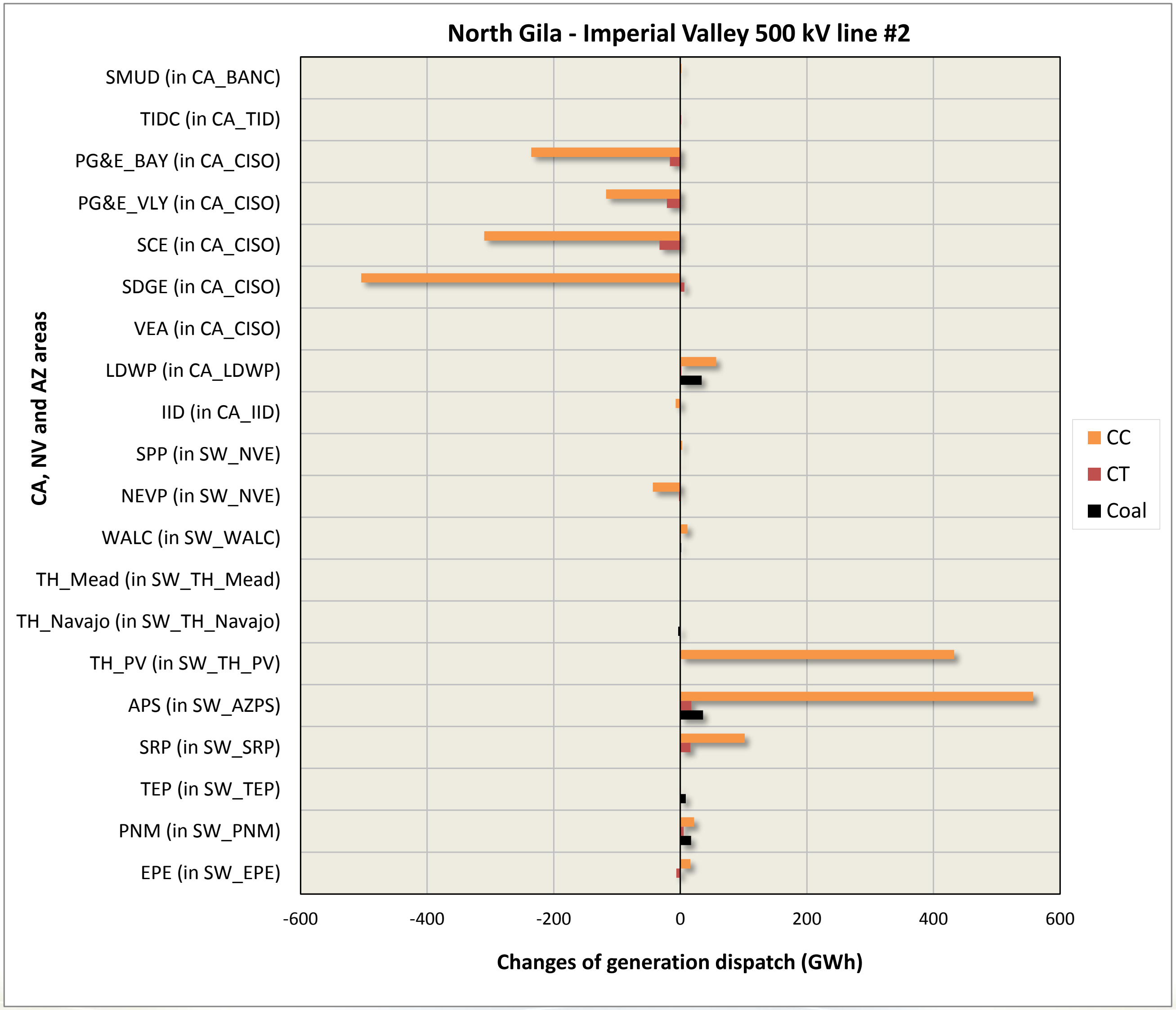
Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,366	1,293	-73
Perkins – Mead 230 kV line	SRP/APS – WAPA	73	61	-12
Path 26 (Midway – Vincent)	PG&E – SCE	878	830	-48
Julian Hinds – Mirage 230 kV line	SCE	83	77	-6

2023:

Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,526	1,519	-7
Perkins – Mead 230 kV line	SRP/APS – WAPA	13	10	-3
Path 26 (Midway – Vincent)	PG&E – SCE	545	496	-49
Julian Hinds – Mirage 230 kV line	SCE	7	5	-2

Incremental changes of generation dispatch

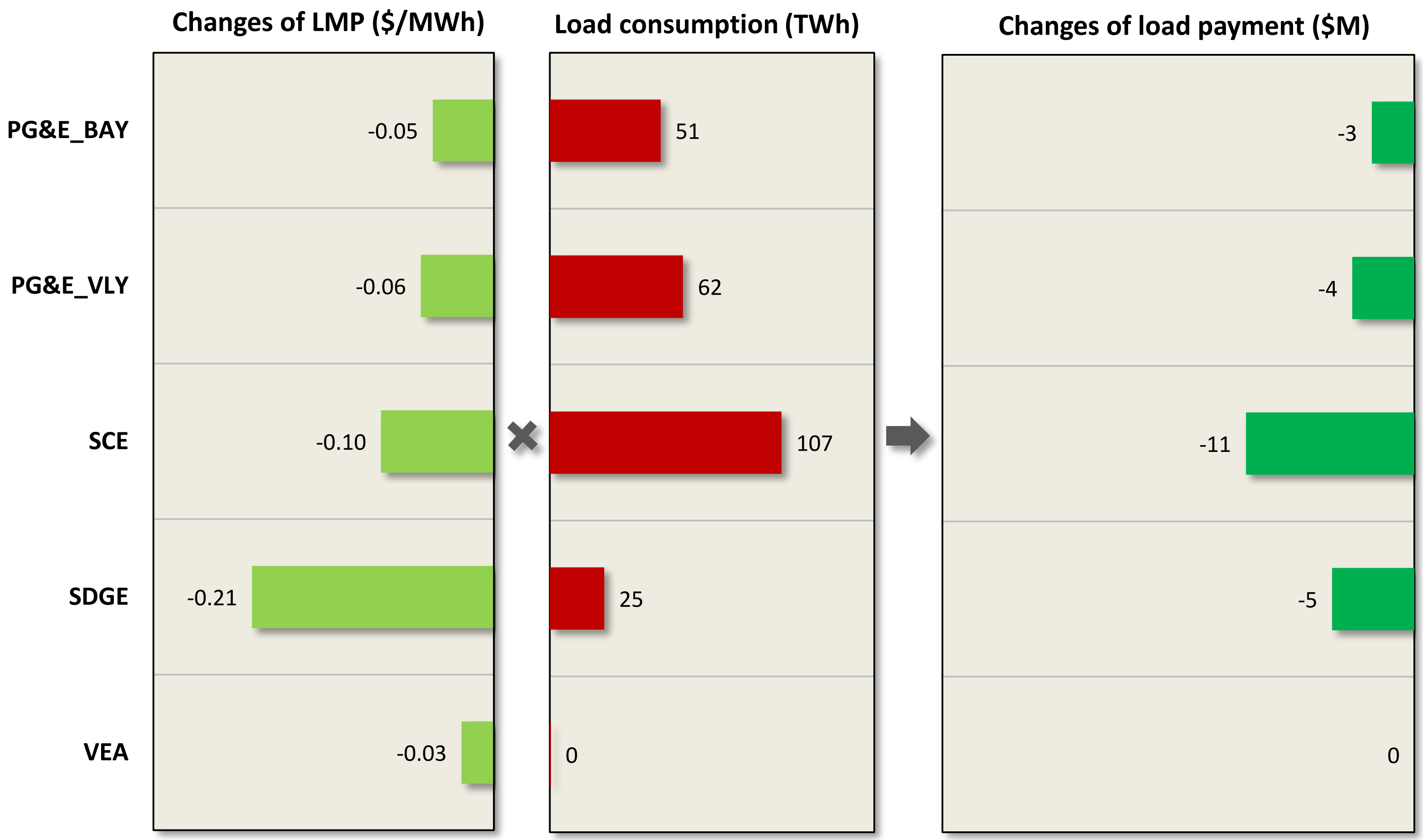
With addition of the North Gila – Imperial Valley 500 kV line #2



Simulation year 2023

Load payment reductions in the ISO-controlled grid

With addition of the North Gila – Imperial Valley 500 kV line #2



Simulation year 2023

The “Changes of LMP ($/MWh)” is the difference of annual averages

Determination of yearly production benefits

With addition of the North Gila – Imperial Valley 500 kV line #2

Year	Production		Part 1		Part 2
2018	$21M	=	$21M	+	$0M
2023	$20M	=	$20M	+	$0M

Where:

Part 1		Consumer	Producer	Transmission
$21M	=	$22M	$0M	-$1M
$20M	=	$23M	-$2M	-$1M

Computed by GridView production simulation for 8,760 hours in each study year by comparison of "pre-project" and "post-project" cases

Part 2		Losses reduction benefit
$0M	=	~0 MW * 8760 hours * $40.15/MWh

Losses reduction calculated by PSLF power flow

Average LMP in 2023 in SCE area

Determination of yearly capacity benefits

With addition of the North Gila – Imperial Valley 500 kV line #2

Capacity benefit is determined to be zero:

1. **System RA benefit is zero because of downstream bottleneck**
2. **LCR benefit is zero**

Cost-benefit analysis for “SWC-3”

North Gila – Imperial Valley 500 kV line #2

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	21	21	21	20	20	20	20	20	…
Capacity benefit	-	-	-	-	-	-	-	-	…
Total yearly benefit	21	21	21	20	20	20	20	20	…

Assumed operation year →	2018
Total benefit Sum of discounted yearly benefits	279
Total cost Total revenue requirement	428

295	Total capital cost

Net benefit	(149)
Benefit-cost ratio	0.65

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Results summary

Evaluation of economic benefits to the ISO ratepayers

Proposed upgrades			Economic assessment			
ID	Transmission Facilities	Operation year	Benefit	Cost	BCR	Assessment
P26-3	Build Midway – Vincent 500 kV #4 (110 miles)	2023	$55M	$1,595M	0.03	Uneconomic
NWC-1	Increase PDCI capacity by 500 MW	2018	$50M	$435M	0.12	Uneconomic
SWC-1	Harry Allen – Eldorado 500 kV line (60 miles)	2020	$240M	$174M	1.38	Further study
SWC-2	Delaney – Colorado River 500 kV line (110 miles)	2020	$516M-762M	$498M	1.04-1.53	Economic
SWC-3	North Gila – Imperial Valley 500 kV line #2 (80 miles)	2018	$279M	$428M	0.65	Uneconomic

Note:
The US dollars are in year 2012 values
The benefits and costs are net present values at the proposed operation year
The “benefit” is the total economic benefit determined by the economic planning study
The “cost” is the total revenue requirement that includes impacts of capital costs, tax expenses, O&M costs, etc.

Thanks!

Your questions and comments are welcome

Please send your comments to:
RegionalTransmission@caiso.com

Transmission Program Impact on High Voltage TAC
Preliminary Results

Draft 2013-2014 ISO Transmission Plan Stakeholder Meeting

Neil Millar
Executive Director - Infrastructure Development
February 12, 2014

Background

- Forecasting tool developed in the 2012-2013 Transmission Plan in response to concerns over increasing upward pressure on transmission costs.
  - Replacing aging infrastructure
  - Complying with NERC planning standards
  - Meeting California energy policy goals
- Goal is to estimate future high voltage transmission access costs in an objective and transparent manner.
  - Strike a balance of top down estimates with bottom up details
  - Provides transparency to costs related to reliability, policy, and economic driven projects
  - Establish a baseline and allows the flexibility to customize each future project individually
  - It is not a precise forecast of any individual PTO’s revenue requirement or any individual project’s revenue requirement

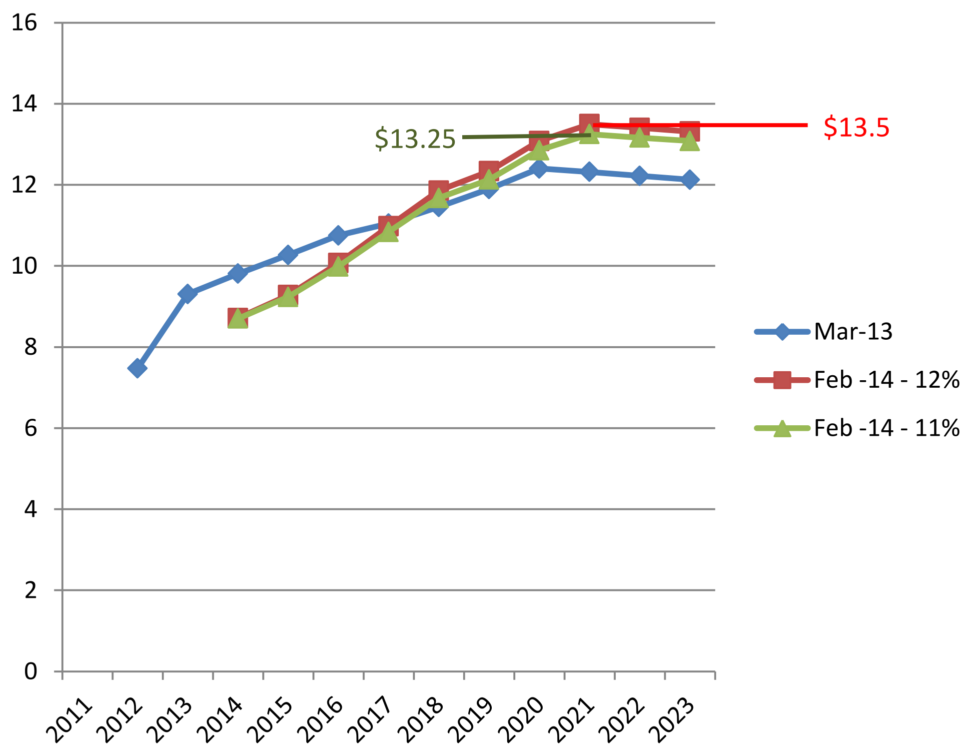
The Forecasting Tool has been updated by:

1. Reviewing comments received on last year's model
2. Establishing a Solid Foundation – January 1, 2014
   - The model accurately reflects current gross plant data
   - Uses reasonable assumptions for costs associated with capital maintenance and O&M
   - Includes other important factors such as depreciation, taxes, and capital costs
3. Adding the Costs of Forecast Capital Additions
   - Costs of Capital
   - Treatment of Construction Work in Progress
   - Financing and Tax Structure
   - Estimated Incremental O&M

Simplified modeling assumptions:

- O&M costs escalated at 2%/year.
- Capital maintenance estimated at 2% of gross plant per year.
- Reliability projects assumed to not drop below $250 million per year once exceeding that level.
- Only major GIP-driven network projects have been identified.
- No adjustment made (yet) for other GIP-driven network upgrades or future ADNUs.
- “Typical” return, tax and depreciation rates applied.

ISO projecting a steady increase in the high voltage transmission access charge over next eight years. –



Note – existing returns are maintained for existing PTO rate base; the impact of 11% and 12% return on equity have been tested for new transmission capital.

Next Steps

- Continue to refine assumptions and costs based on comments received
- Include updated results in revised draft Transmission Plan
- Provide annual updates as part of annual transmission planning process

California ISO
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Eligibility for Competitive Solicitation

Draft 2013-2014 ISO Transmission Plan Stakeholder Meeting

Neil Millar
Executive Director - Infrastructure Development
February 12, 2014

New simplified tariff criteria for eligibility for competitive solicitation provisions:

- Reliability, Policy and Economically Driven regional (over 200 kV) facilities are eligible for competitive solicitation, except:
  - If the transmission solution adopted in Phase 2 involves an upgrade or improvement to, addition on, or a replacement of a part of an existing Participating TO facility, the Participating TO will construct and own such upgrade, improvement, addition or replacement facilities unless a Project Sponsor and the Participating TO agree to a different arrangement.

- Key changes from criteria in effect in last year's plan:
  - Competition broadened to included reliability-driven projects without need for policy or economic benefits test.
  - Criteria aligned with transition to regional/local distinction consistent with approved portions of ISO's FERC Order 1000 regional compliance filing.

Eligibility for competitive solicitation:

- Reliability-driven:
  - Imperial Valley flow controller
  - Estrella 230/70 kV substation*
  - Wheeler Ridge Junction 230/70 kV substation*
- Policy-driven:
  - Suncrest 300 Mvar SVC
- Economically driven:
  - Delaney-Colorado River 500 kV transmission line

* Only the 230 kV facilities including the 230/70 kV transformers are eligible for competitive solicitation; the 70 kV facilities are not.

Next steps in competitive solicitation process:

- Key selection criteria for each project will be identified by the end of February.
- Competitive solicitation process will be launched in April after the Board of Governors approval of the transmission plan in March.
- BPM being revised now to provide more clarity in scheduling based on existing tariff:
  - Final FERC order on selection criteria not yet received.
  - BPM will need to be revised again to reflect final FERC order.
- ISO intending a “lessons learned” exercise:
  - Changes that don’t require tariff changes may be incorporated into BPM to apply to 2013/2014 cycle.
  - Changes that do require tariff changes will be incorporated into 2014/2015 cycle.

Next Steps

Draft 2013-2014 ISO Transmission Plan Stakeholder Meeting

Tom Cuccia
Sr. Stakeholder Engagement and Policy Specialist
February 12, 2014

Next Steps

Date	Milestone
February 26	Stakeholder comments to be submitted to regionaltransmission@caiso.com
No later than March 12	Post Revised Draft 2013-2014 Transmission Plan
March 19-20	Present Revised Draft Plan to ISO Board of Governors
March 21	Post Final 2013-2014 Transmission Plan
April 1	Phase 3 Competitive Solicitation Period Opens *

* Refer to the Transmission Planning Process Business Practice Manual for the rest of the steps for Phase 3 of the ISO transmission planning process.