Energy+Environmental Economics

Workshop Discussion: California LNBA Update

September 20th, 2017

Agenda

- **Context for Distributed Resource Planning (DRP)**
  - Locational Net Benefits Analysis (LNBA)
- **Methodology for Distribution Avoided Costs**
  - References, formulas, elements of the approach
- **Implementation in Public LNBA Tool**
  - Data and definitions
  - Tool overview
- **Discussion**
  - Next steps in California

History in California of Locational

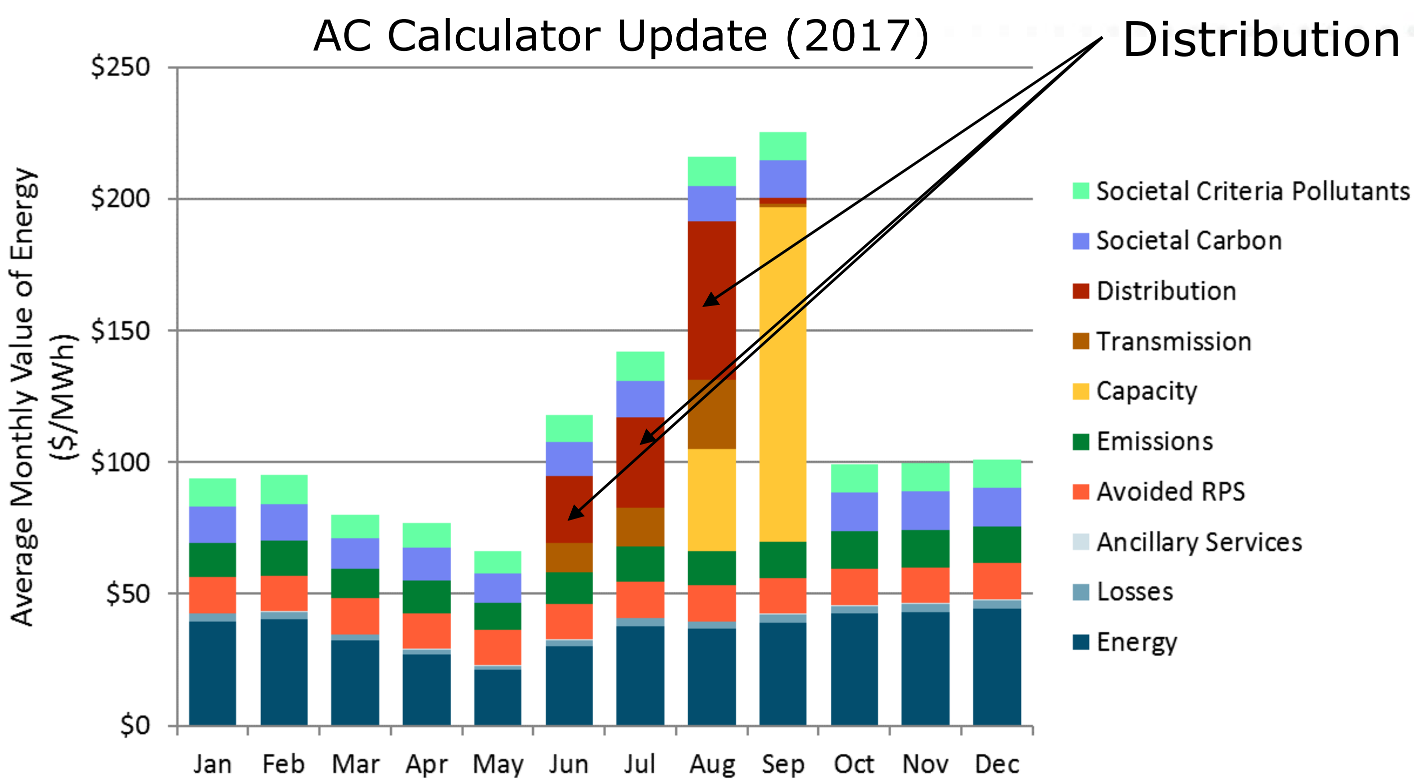
- **Doing non-wires studies since 1989…**
  - California has a long history of looking at the local value of distributed energy resources
- **In 2004, local value integrated into the avoided costs for utility DER programs**
  - Local value differentiated by climate zone included in the avoided costs of energy efficiency, expanded to solar rooftop, demand response, storage, and other DERs
- **Legislated in 2014 Assembly Bill (AB) 327**
  - Requires each utility "to identify optimal locations for the deployment of distributed resources…" based on "locational benefits and costs of distributed resources"

E3 History of Targeted T&D Studies

Utility	Study Name	Year
PG&E	Kerman PV Study	1990
PG&E	EPRI Delta Study	1992
Ontario Hydro	Collingwood	1993
PG&E	Integrated Generation, Transmission, and Distribution (IGTD) Study	1994
CSW -CP&L	Laredo	1994-1995
Ontario Hydro	Toronto Integrated Electric Supply (TIES) Study	1995
WEPCO	Strategic Distribution Planning Study	1995
TVA	Nashville Electric Service	1996
Commonwealth Edison	Far Northwest Planning Area	1997
Orange and Rockland Utilities	Middletown Tap	1999
PG&E	Tri-Valley	1999
Consolidated Edison of New York	Rainey-E 75th	2000
PG&E	San Francisco Jefferson-Martin	2001
Consolidated Edison of New York	DG RFP	2002
PG&E	Delta 21kV	2003
BPA	Olympic Peninsula Non-wires Alternative	2003
BPA	Kangley-Echo Lake	2003
CEC Renewable DG Assessment	Sacramento Municipal Utility District, City of Palo Alto, Alameda Power and Telecom, SF Hetch-Hetchy	2004-2006
CEC PIER	San Francisco Distributed Energy Resources Testbed	2004-2007
Vermont PSC	Transmission deferral	2009
Orange and Rockland Utilities	Orangeburg Substation	2010
BPA	Hooper Springs	2011
BPA	I-5 Corridor	2011

Integrated into the Avoided Costs for Efficiency and Other Programs

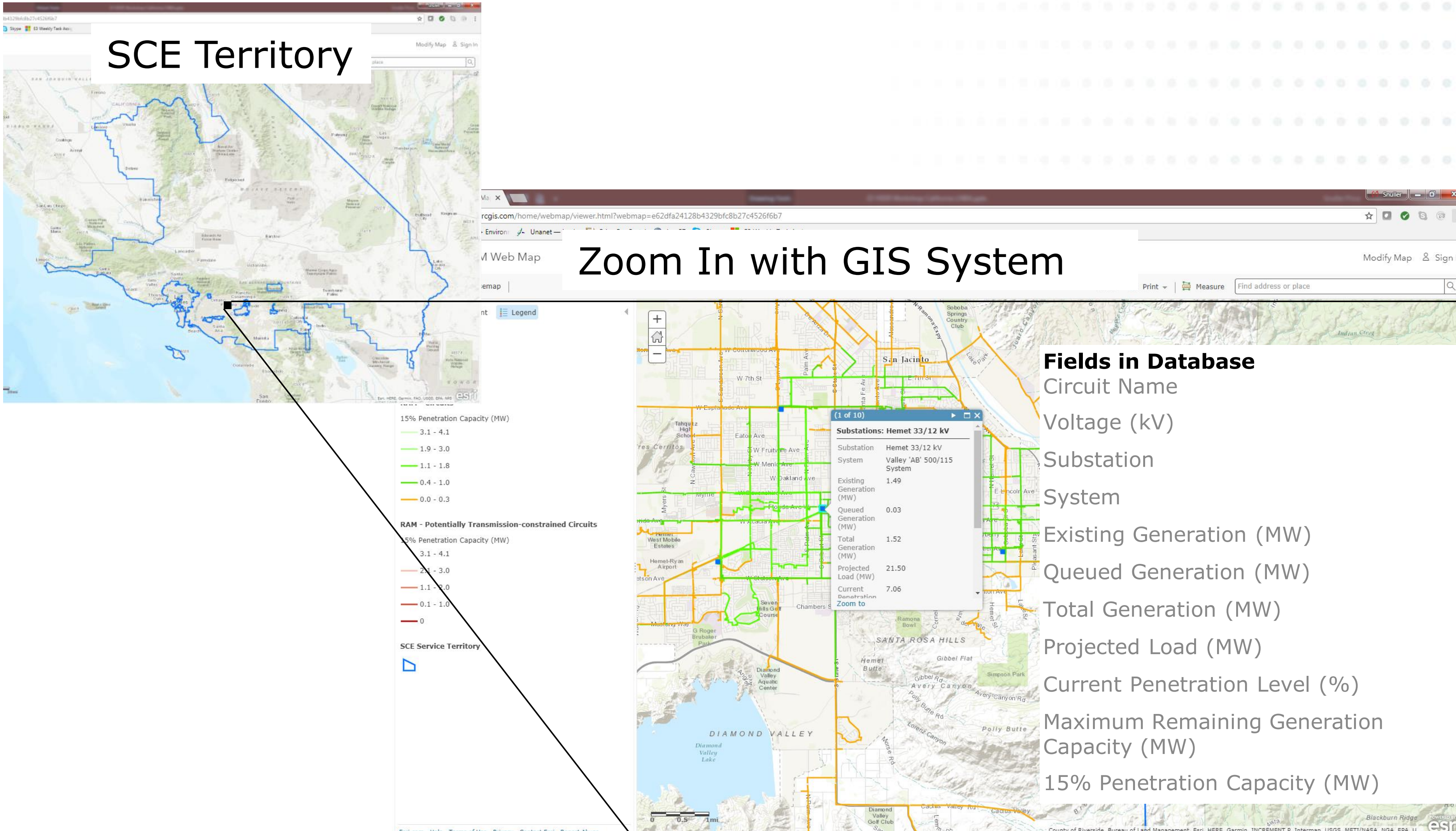
- Avoided Cost Calculator since 2004
- Hourly avoided costs by component
- 16 climate zones (May 2018 will be ~500 zones)



Distribution Resource Planning (DRP)

- **Two Areas of Focus**
  - Demo A on interconnection, integrated capacity analysis (ICA) working group to develop common utility process
  - Demo B on local capacity value,
- **Utility non-wires solutions solicitations (current)**
- **Maps of targeted areas and LNBA tool development**
- **Website with materials and the publicly available LNBA tool (that E3 developed)**

Interconnection Maps, SCE Example



Fields in Database

- Circuit Name
- Voltage (kV)
- Substation
- System
- Existing Generation (MW)
- Queued Generation (MW)
- Total Generation (MW)
- Projected Load (MW)
- Current Penetration Level (%)
- Maximum Remaining Generation Capacity (MW)
- 15% Penetration Capacity (MW)

http://on.sce.com/derim

California Emerging Applications Next Steps

- **Integrate local avoided cost in DER program cost-effectiveness, target date of May 31, 2018**
  - Up to 500 distribution planning areas are possible
- **Develop iDSM tool with particular focus on solar plus storage for targeted DER deployment.**
  - Optimal least cost portfolio versus the traditional solution
- **Grow offerings of targeted local demand response programs, both price- and utility control-based**

New York Doing Local Studies Too…

+ NY Restructuring Agreement 20 Years Ago

4. The Company agrees to address certain restructuring-related issues raised by the Natural Resources Defense Council and others as follows:

Deferral of T&D Capital Projects:	The Company will continue to develop detailed annual forecasts of transmission and distribution ("T&D") capital budget requirements and will identify for each major T&D project (i.e., projects of $10 million or more), the location, reason for project, scope of project, projected capital costs, appropriate load and other data. The Company will also perform load monitoring consisting of monitors at a significant sample of the transmission and area substations scheduled for expansion/upgrade in the five-year T&D capital plan. The Company will evaluate and implement cost-effective measures as alternatives to major T&D projects that defer major T&D system projects through the use of technologies or services that could reduce peak T&D loads. For such cost-effective projects, consideration will be given to technologies or services that minimize the environmental impacts of electricity usage including demand side and other new technologies where practicable. Con Edison will continue to seek to minimize costs and environmental impacts for T&D projects that are not major T&D projects.

METHODOLOGY FOR DISTRIBUTION VALUE

Academic References

+ Select Publications of Local Area Distribution Marginal Capacity Cost

- R. Orans, "**Area-Specific Marginal Costing for Electric Utilities: A Case Study of Transmission and Distribution Costs**", Ph.D. Dissertation, Stanford University Dept. of Civil Engineering, 1989
- C.K. Woo, R. Orans, B. Horii, R. Pupp, G. Heffner "**Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution**" Energy Vol. 19., No. 12, pp. 1213-1218, 1994
- J. Swisher, R. Orans "**The Use of Area-Specific Utility Costs to Target Intensive DSM Campaigns**" Utility Policy Vol. 5, No. 3/4, 1995
- C.K. Woo, D. Lloyd-Zanneti, R. Orans, B. Horii, and G. Heffner, "**Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation**", The Energy Journal, Vol. 16, No.2, 1995
- G. Heffner, C.K. Woo, B. Horii, and D. Lloyd-Zannetti, "**Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution**", IEEE Transactions on Power Systems, v13n2, May 1998, pp 560-565.

Present Worth Method Formulas

- Core valuation element is the "differential revenue requirement" or "present worth method"
- Marginal distribution capacity avoided cost

$$PW\ Value\ \left(\frac{\$}{\mathrm{kW}}\right) = \frac{\mathrm{Capital\ Cost(\$)} * \mathrm{RR\ Adj}\left(1 - \left(\frac{1+i}{1+r}\right)^{\Delta t}\right)}{\mathrm{Required\ Load\ Reduction\ (kW)}}$$

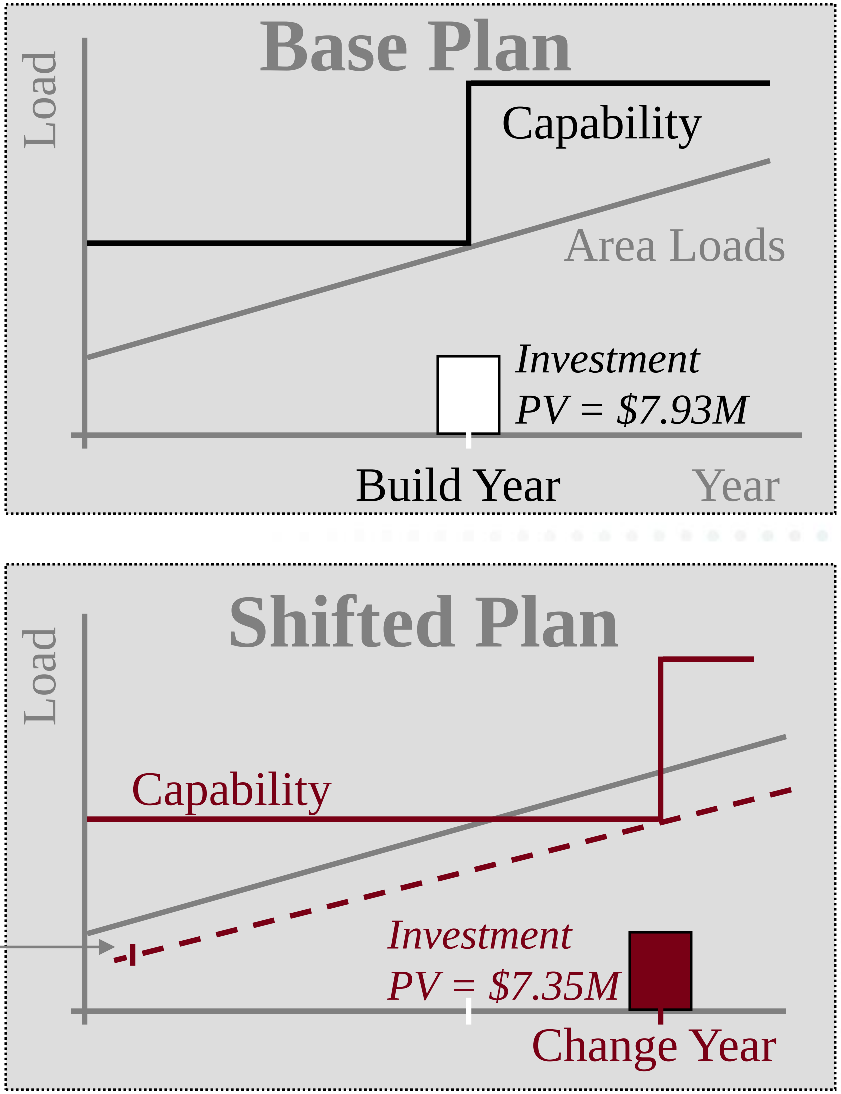
- Levelized Value

$$\mathrm{Annual\ PW\ Value}\left(\frac{\$}{\mathrm{kW-year}}\right) = \mathrm{PW\ Value}\left(\frac{\$}{\mathrm{kW}}\right) * \mathrm{RECC}$$

$$\mathrm{RECC} = \frac{(r-i)}{(1+r)}\frac{(1+r)^n}{[(1+r)^n - (1+i)^n]}$$

Present Worth Method is Based on Deferral of Investments

- Load decrease delays investment need
- Present value of deferral is calculated as PV(base plan) - PV(change plan)

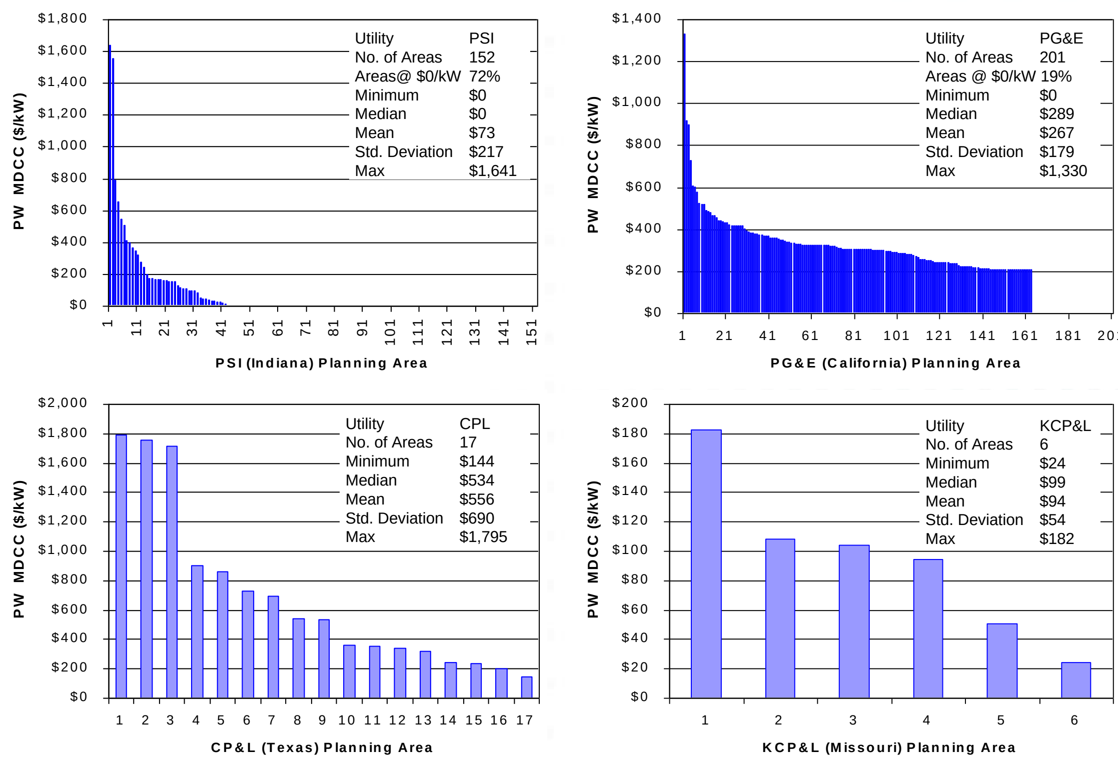


Load Change

Historical Examples of 4 Utilities

- Differentiate plans/costs by geographic area.
- Resolution set by circuit boundaries usually distributio planning area.
- Reveals tremendous locational variatio and high-value areas for DR.

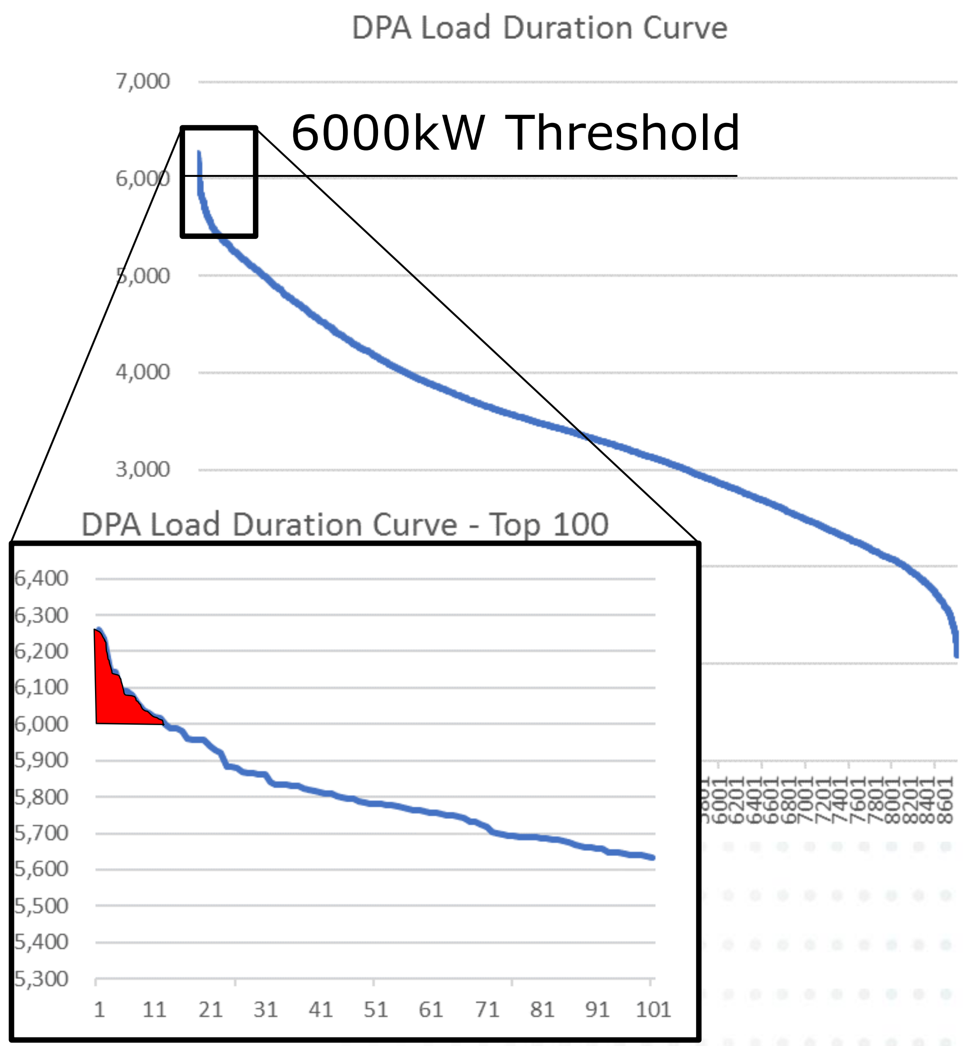
Survey of Distribution Costs System Wide



G. Heffner, C.K. Woo, B. Horii, and D. Lloyd-Zannetti, "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution", IEEE Transactions on Power Systems, v13n2, May 1998, pp 560-565.

Peak Capacity Allocation Factors

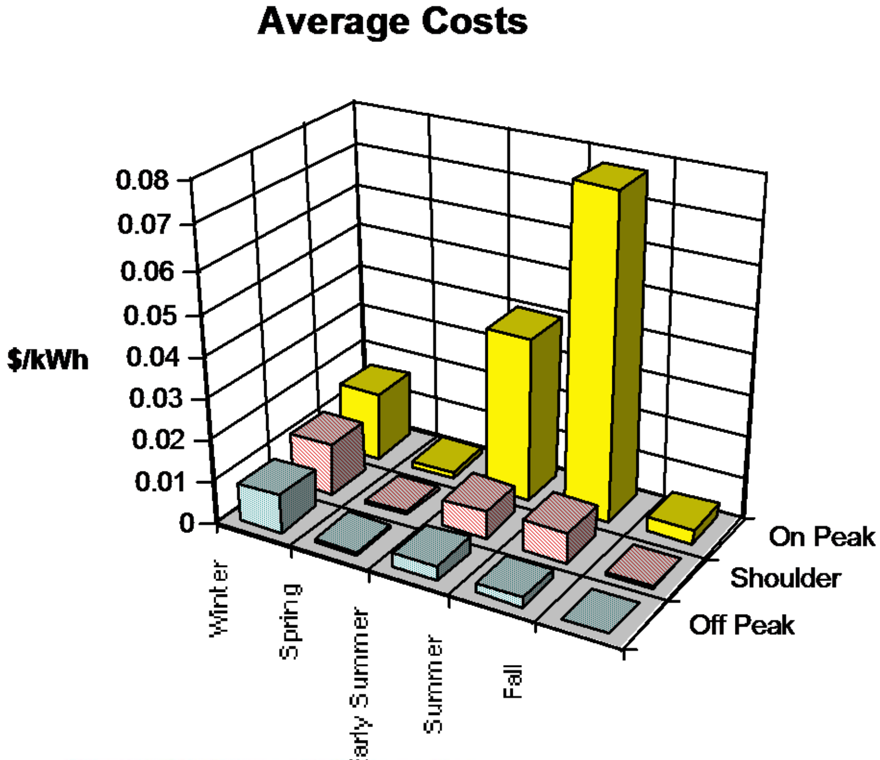
- **Allocation to hours for distribution similar to loss of load probability (LOLP)**
  - Allocate the full distribution capacity cost to hours based on the probability of exceeding peak
- **Formulation is used to evaluate probability in each hour based on historical load**

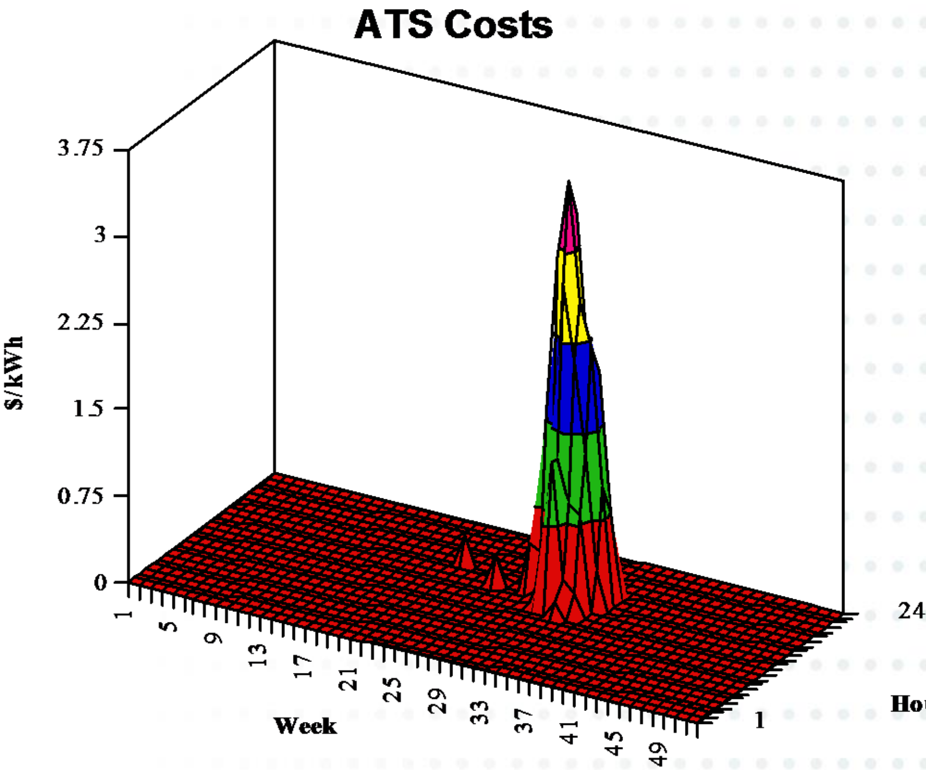


Allocate costs to time based on timing of engineering need

- Many distribution investments are built for less than the top 50 load hours (planning based on single peak)

Comparison of Time-of-Use vs. Hourly





Distributional Marginal Costing Methods Comparisons

- **Present Worth Method is the only method to isolate forward looking avoided cost at a particular location and time, area- and time-specific value**

Table 10: Marginal Costing Methods

Marginal Costing Method	Description	Comments
Total Investment Method - TIM	Discounted capital budget cash flow divided by additional peak demand.	Longer time horizon appears less expensive. Cannot compare areas with different timing.
Discounted Total Investment Method – DTIM	Discounted capital budget cash flow divided by discounted additional peak demand.	Equivalent to constant $/kW payment needed to match cash flow. Does not capture avoided cost of a kW saved.
Present Worth – PW	Deferment value from shifting optimal capital plan in time due to change in peak demand from base case.	Captures avoided cost of a kW saved.
Regression Method (NERA) – RM	Slope of linear regression based on historical and forward-looking cost vs. demand.	Historical costs skew results. Does not capture avoided cost of a kW saved.
Replacement Cost New – RCN	Average cost based on cost to replace. Marginal cost based on "engineering elasticity" derived from simulation.	Does not reflect actual costs.

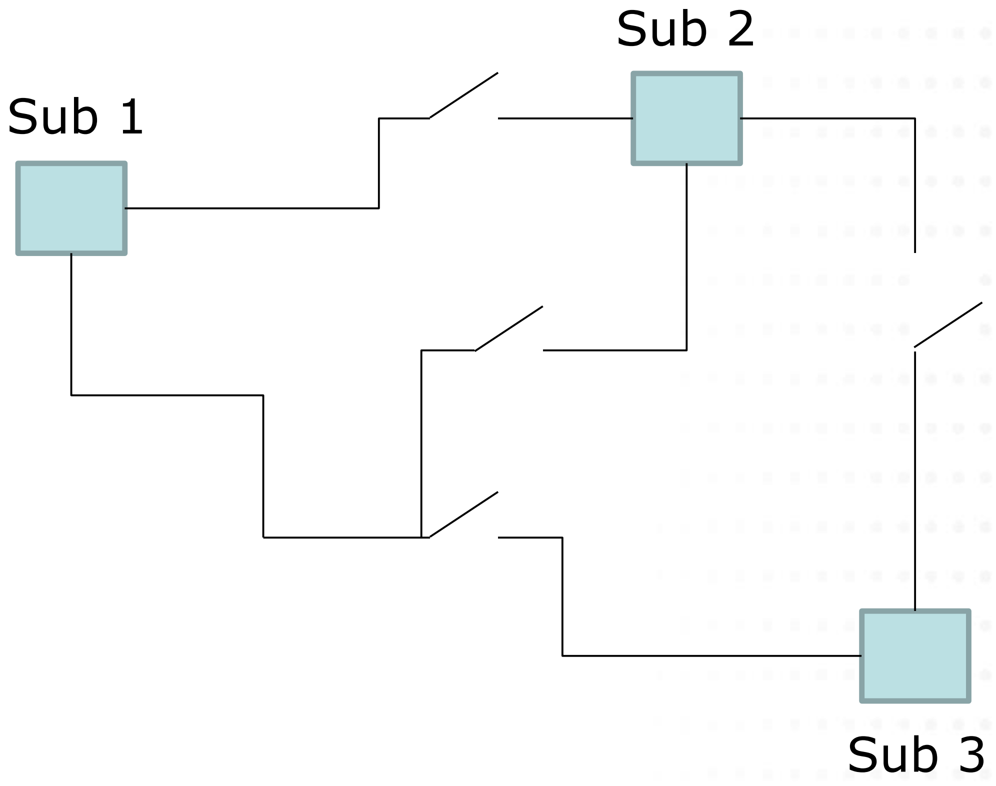
IMPLEMENTATION: DATA AND DEFINITIONS

Data Sources for Distribution Cost

- **Capital budget plans and load growth provided by each IOU in response to CPUC data request**
  - Capital budget plans isolated to load growth driven investments
  - Load growth by area provided in data request
- **Defining "Distribution Areas"**
  - SCE defined by SYS ID areas; broader than other IOUs
  - PG&E defined by DPAs
  - SDG&E by distribution substation
- **Local area load data**
  - Aggregated hourly bank loads for target DPAs
  - SCADA and hourly data not available for all areas

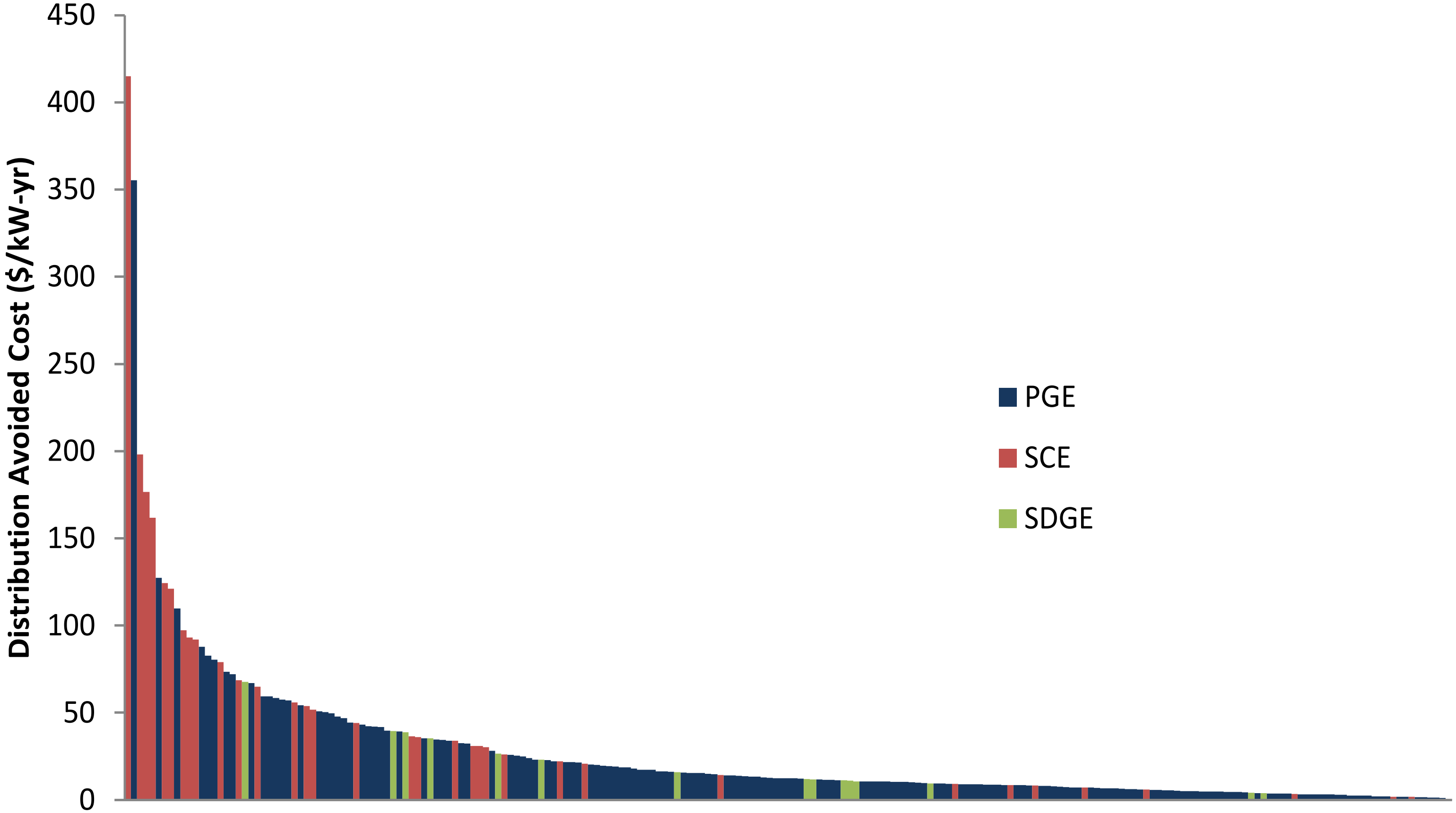
Distribution Planning Area Definition for LNBA Purposes

- Distribution Planning Area (DPA) is an area where load cannot be easily switched outside of the area

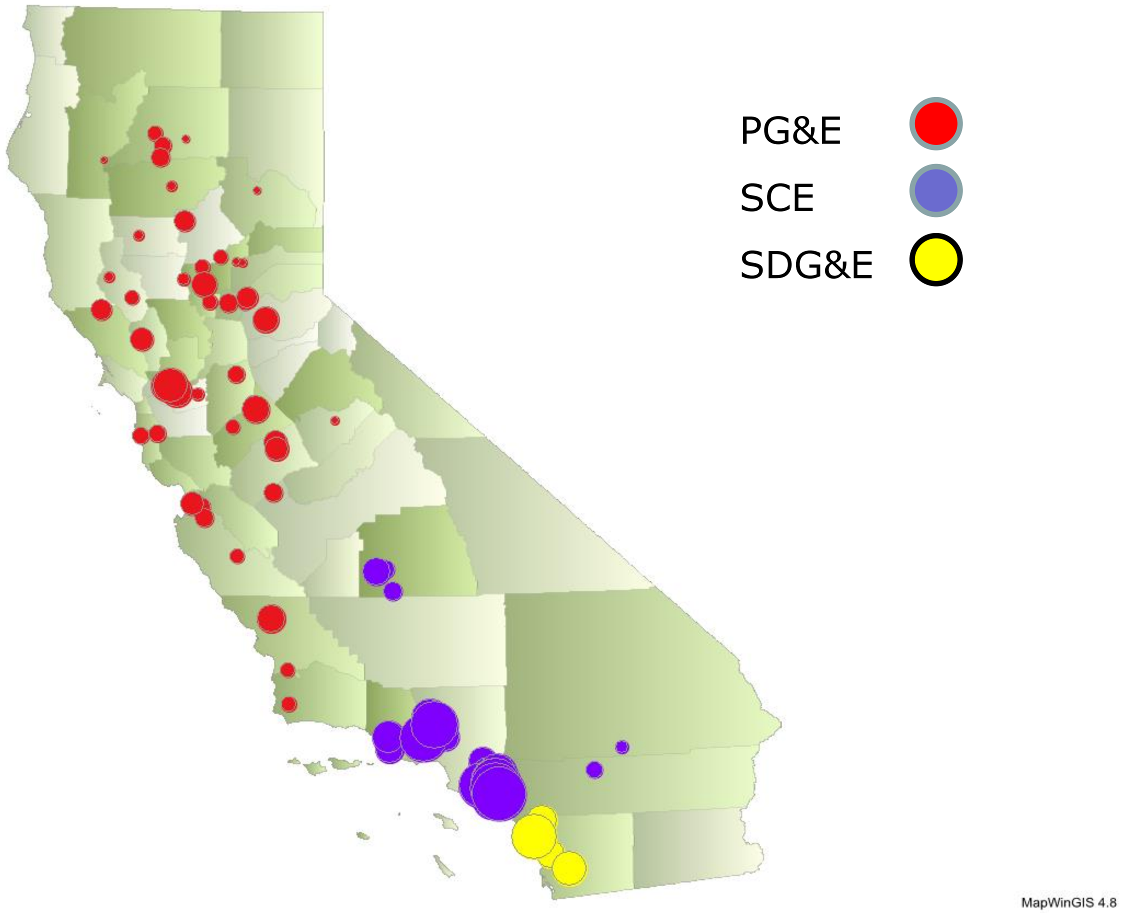


Distribution Avoided Costs

Distribution Avoided Costs by Planning Area ($/kW-year):



Location of Hot Spots from Avoided Cost Data*



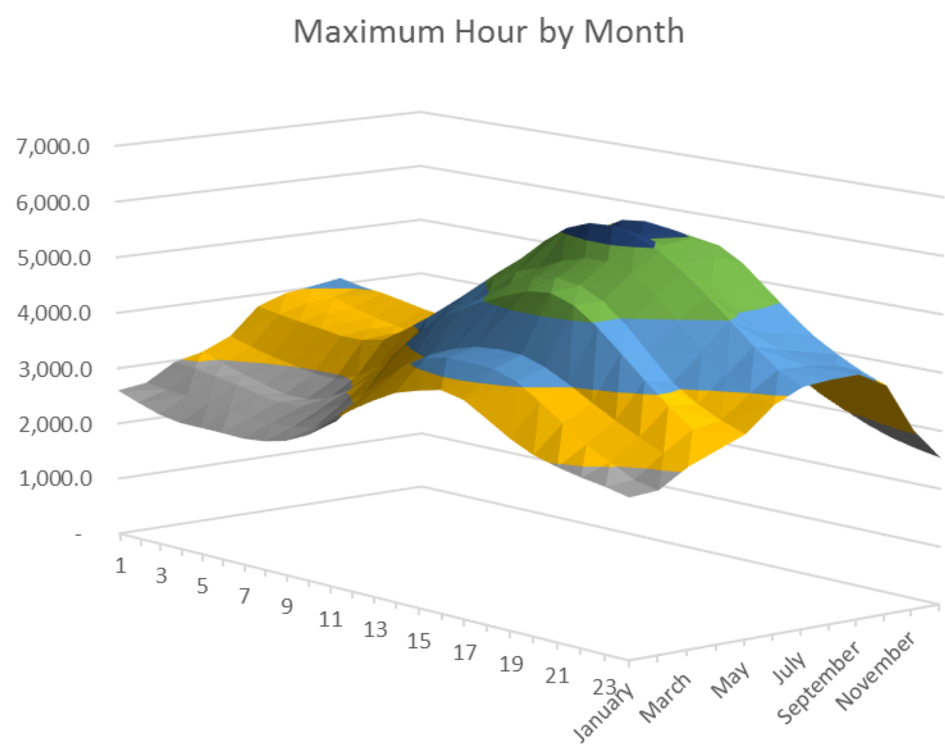
Share of Load Represented

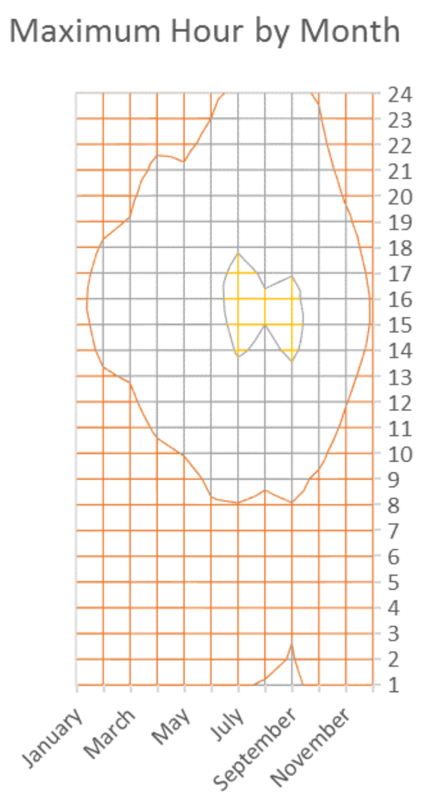
SCE	10% of load
PG&E	5% of load
SDG&E	5% of load

* Proposal is that each utility identify the 'hot spots' in their service territory

Local Area Load Shape

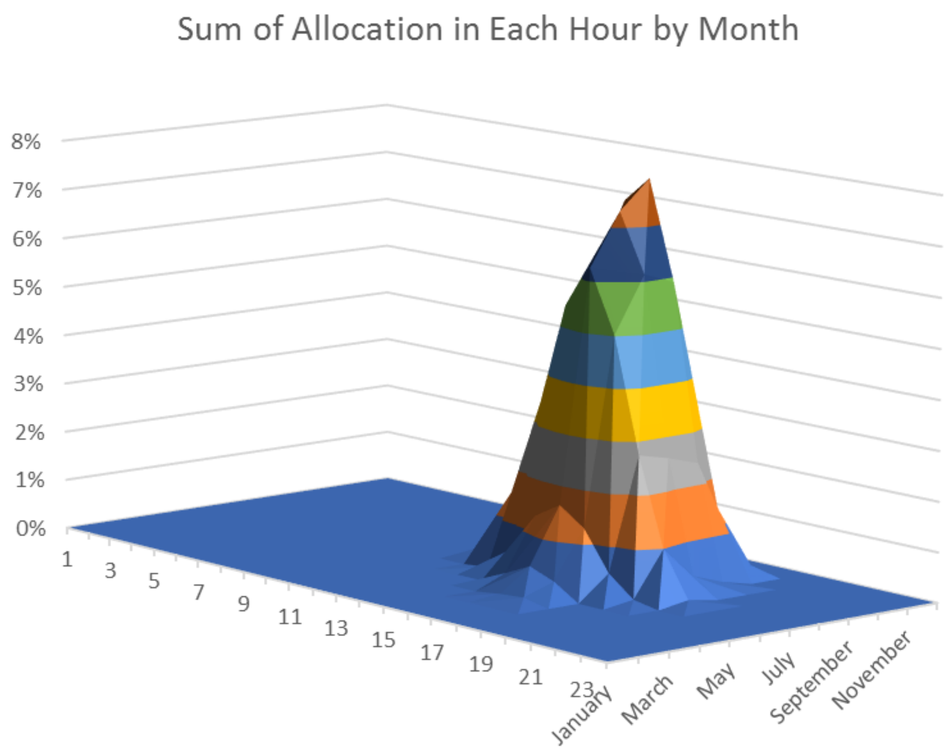
+ Distribution Planning Area Load

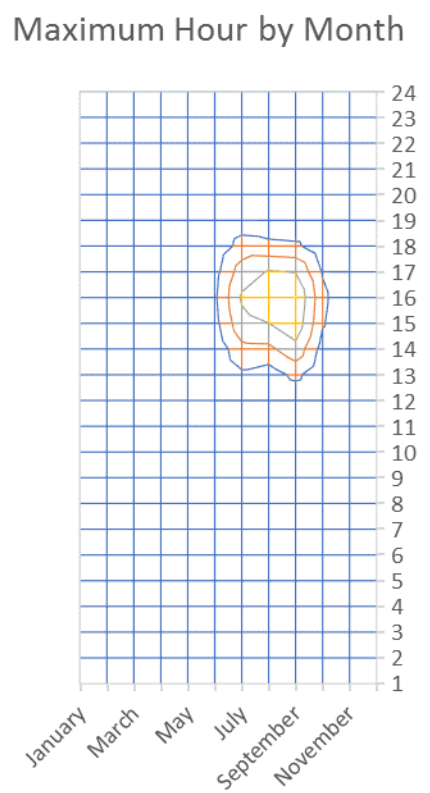




Local Area Peak Allocation Factor

+ Allocation of Distribution Capacity Value





IMPLEMENTATION:
LNBA TOOL & NEXT STEPS

LNBA Tool

- **Joint California IOU standardized methodology for all components of the avoided cost**
- **Example publicly available on LNBA Working Group**
  - URL http://drpwg.org/sample-page/drp/
- **Includes hourly costs and benefits for the life of the DER Resource up to 30 years, using standardized avoided cost calculator (ACC) method**
- **Designed for non-wires solution RFO submission**

LNBA Interface

+ MS Excel, Multiple tabs

LNBA v2.11 - Excel

DER Settings and Full Local T&D Avoided Cost — **Version 2.11**

DER Location and Annual Inputs		
DER Location	Circuit 1102	
Dependability in local area (eg.g: 90%)	90%	
DER Useful Life (yrs)	20	
DER install year	2018	*InstallYr*
Defer T&D to this year (Max 2026)	2020	

DER Type	SOLAR	
Integration cost adder ($/MWh)	$ 3.00	
Transmission Avoided Cost ($/kW of DER)	$0.00	(Default = 0)
Generation Capacity LCR Multiplier	1.0	(Default = 1.0)

DER impact on local T&D

T&D Value Basis: Allocation-based average

"Requirement-based threshold" assigns value for the project area only if peak reduction is sufficient for deferral. For other affected areas, value is based on the percentage of the kW need that is met by the DER. The user can "exclude" other affected projects to force the attributed value to zero.
"Allocation-based average" is based on expected reductions and is not limited to discrete integer years of deferral.
"Allocation-based average" calculates value using peak capacity allocation factors (see below for a description of PCAFs)..

DER Peak Reductions

	kW Needed	Need after Dependable DER (kW)	Dependable DER Reduction (kW)	Sufficient for deferral?	Potential Deferral Value ($)	Include or Exclude Deferral Value (?)	**Attributed Deferral Value ($)**
Circuit 1102	2812	3189	-377	FALSE	$396,370	Include	**$161,241**
Other affected T&D Projects							
Circuit 1107	512	0	512	TRUE	$360,327	Include	**$1,058,438**
Dist Infra 2	6211	5889	623	FALSE	$0	Include	**$0**
DPA 1	512	-109	621	TRUE	$0	Include	**$0**
0	0	0	0	TRUE	$0	Include	**$0**
0	0	0	0	TRUE	$0	Include	**$0**
0	0	0	0	TRUE	$0	Include	**$0**
0	0	0	0	TRUE	$0	Include	**$0**
0	0	0	0	TRUE	$0	Include	**$0**

DER kW output statistics

DER Max Output (kW) 2,739

	Project Area	All Affected Areas	
Minimum	**0**	**515**	*Min DER output during the peak period*
5%	**0**	663	*DER below this 5% of time*
10%	**0**	729	*DER below this 10% of time*
25%	**0**	1,188	*DER below this 25% of time*
Simple Average	**963**	**1,599**	*Average DER during peak period*
PCAF Wtd Average	**1,210**	**1,528**	*Wtd Avg DER during peak period*

Peak capacity allocation factors (PCAF) weight each hourly output based on the amount of relative demand reduction needed in each hour.

Overview | **DER Dashboard** | Project Inputs & Avoided Costs | AreaPeaks | SystemAC | Flex RA | ReM ...

LNBA Capital Expansion Plans

Distribution Capital Plan Inputs and MW Requirement

LNBA v2.11 - Excel

A17

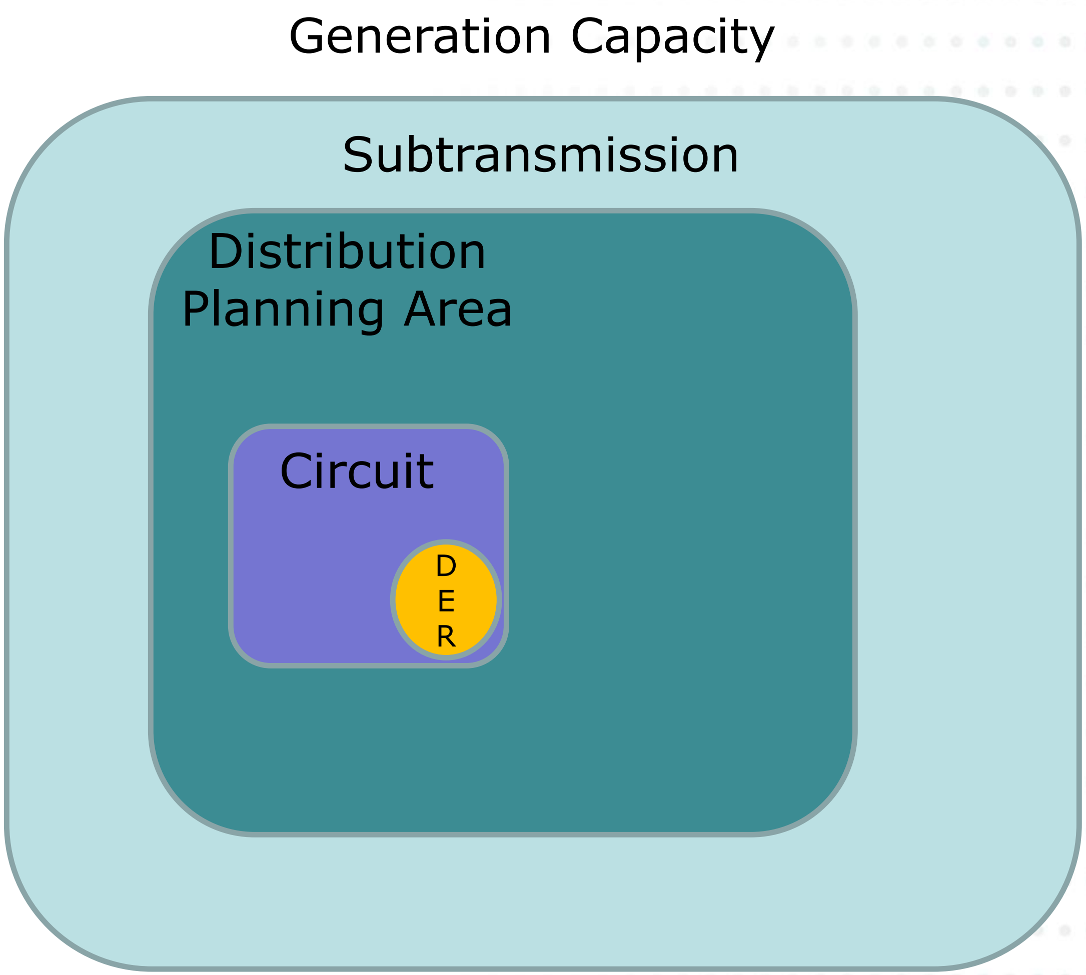
	A	B	C	D	E	F	G	H	I	J	K
16	Project cost and need information										
17		Equipment Information	Item 1					Item 2			
18		Location Identifier (user text)	DPA 1					Circuit 1102			
19		Location Mapping info (User text)	Location 1234					Location 1235			
20		Equipment type	Primary Feeder					Substation			
21		Equipment Inflation (%/yr)	2.0%					2.0%			
22		Revenue Requirement Multiplier	165.0%					155.0%			
23		O&M Inflation Rate (%/yr)	2.0%					2.0%			
24		Book life (yrs)	25					30			
25		O&M Factor (Annual O&M$/Project Cost $)	12.0%	0.12	0.12			10.0%	0.1	0.1	
26		Cost Information	Base	Low	High			Base	Low	High	
27		Capital Cost ($000)	$2,000.0	$1,800.0	$3,000.0			$1,000.0	$800.0	$1,200.0	
28		Incremental O&M Cost ($000)	$240.0	$216.0	$360.0			$100.0	$80.0	$120.0	
29		Cost yr basis	2015					2016			
30		Project install/commitment year	2017					2019			
31											
32		Cumulative MW reduction needed for deferral	Base					Base			
33	1	2017	0.26					2.56			
34	2	2018	0.38					2.68			
35	3	2019	0.51					2.81			
36	4	2020	0.64					2.94			
37	5	2021	0.77					3.07			
38	6	2022	0.91					3.21			
39	7	2023	1.05					3.35			
40	8	2024	1.19					3.49			
41	9	2025	1.33					3.63			
42	10	2026	1.48					3.78			
43											
44											
45	Project Mapping and Flow Factors										
46											

Overview | DER Dashboard | Project Inputs & Avoided Costs | AreaPeaks | SystemAC | Flex RA | ReM ...

Ready

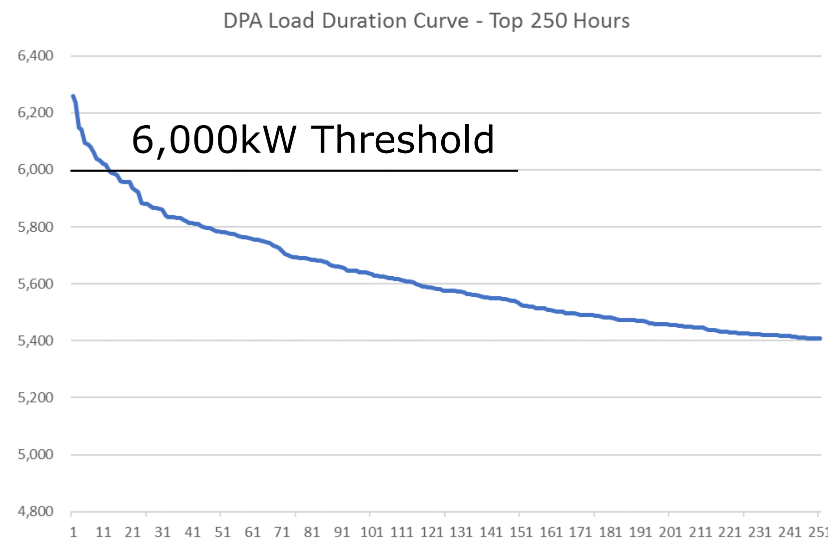
Local Values 'Nest' Together

- **Local capacity values stack**
  - load shape and marginal costs can different in each nest
- **Marginal costs linked to capital investment plan for upgrades**



Peak Allocation Factors

- Allocation of T&D Value in hours with peak loads
- Define a threshold level of concern, can be defined by ratings or judgement level



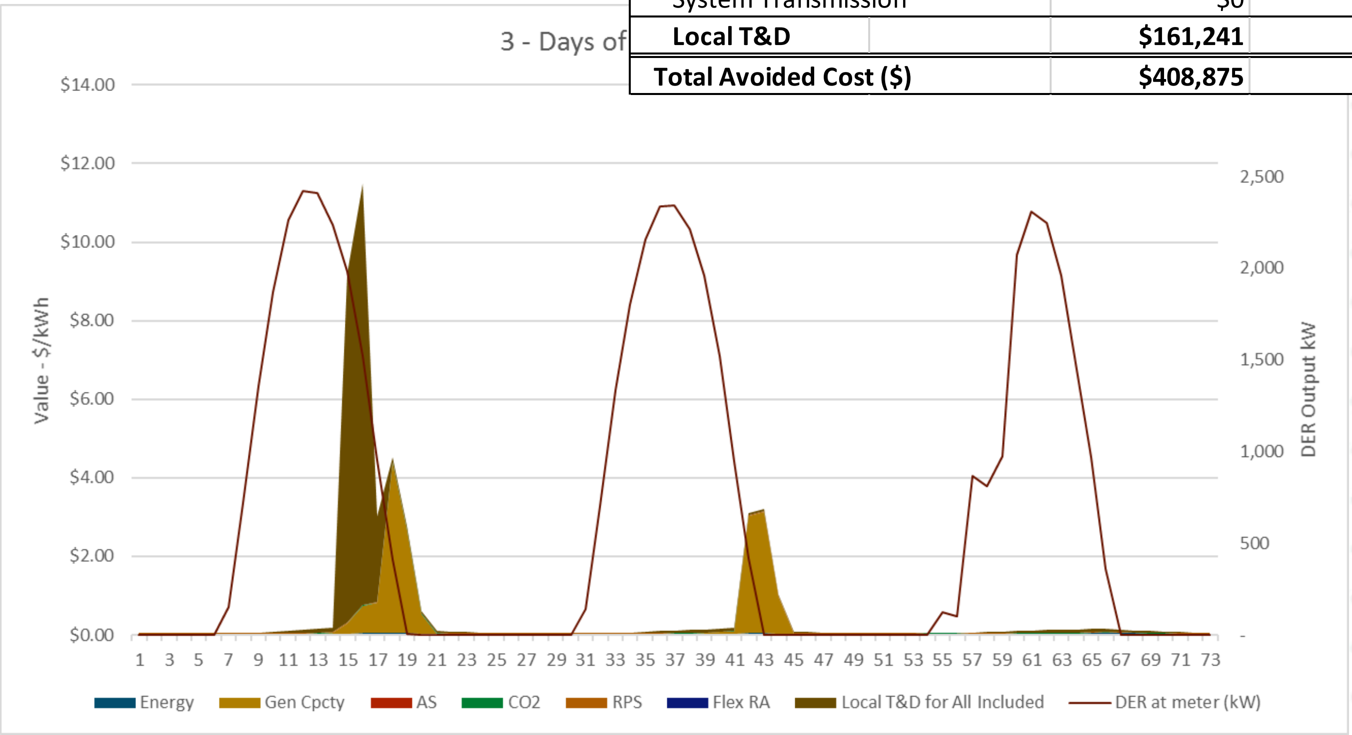
Heatmap of LNBA Local T&D Costs (Total $/kW in each month/hour)

Individual — Hour of the Year (hour starting PST)

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	1	1	1	2	2	2	2	1	1	1	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	1	1	2	2	2	2	2	2	2	2	1	1	1	0	0
Jul	0	0	0	0	0	0	0	0	1	1	2	2	2	3	3	3	3	2	2	2	1	1	1	0
Aug	0	0	0	0	0	0	0	0	0	1	1	2	2	3	3	3	3	3	2	2	1	1	1	0
Sep	0	0	0	0	0	0	0	0	0	1	1	2	2	3	3	3	3	2	2	2	1	1	1	0
Oct	0	0	0	0	0	0	0	0	0	0	1	1	2	2	2	2	2	2	1	1	1	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Value Stack in LNBA Tool

Lifecycle Value from DER by Component ($)			
		Circuit 1102	All Affected Areas
Energy		$129,098	$129,098
Gen Capacity		$43,793	$43,793
Ancillary Services		$1,054	$1,054
CO2		$31,462	$31,462
RPS		$67,385	$67,385
Flex RA		-$10,512	-$10,512
Integration Cost		-$14,647	-$14,647
System Transmission		$0	$0
Local T&D		**$161,241**	**$1,219,680**
Total Avoided Cost ($)		**$408,875**	**$1,467,313**

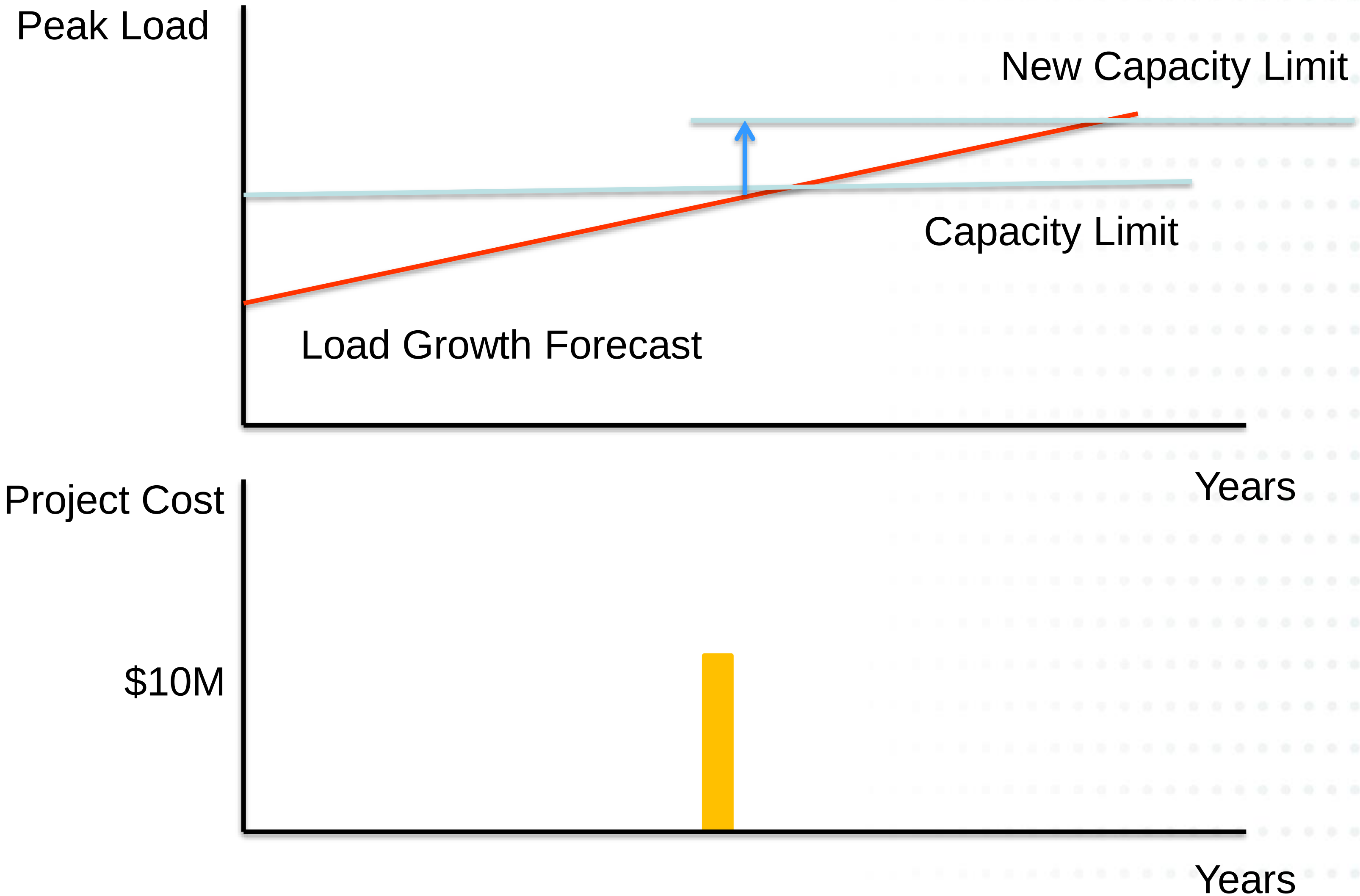


COMPLEXITIES OF DELIVERING VALUE TO RATEPAYERS

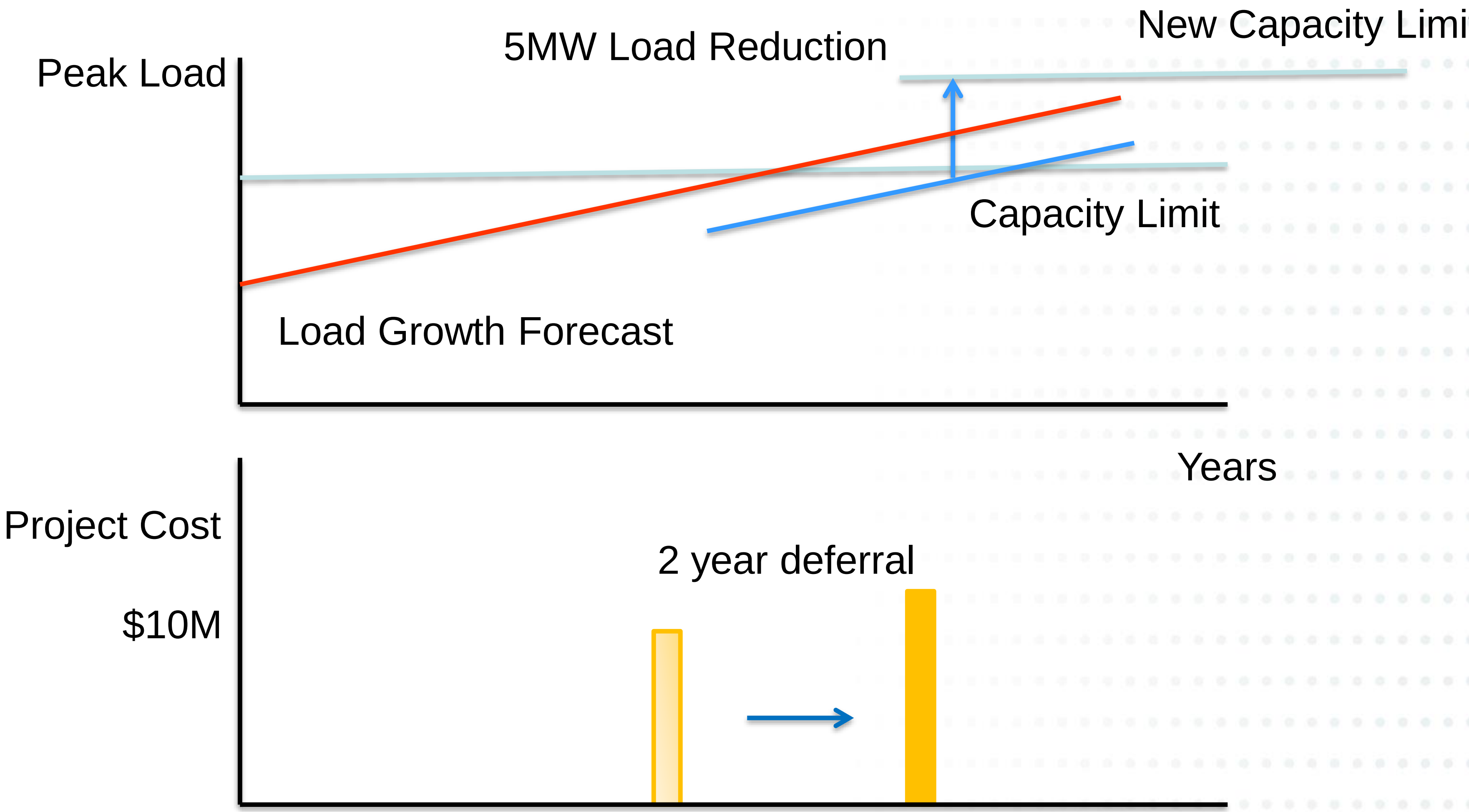
Distribution Planning Process

- **Load forecast of growth in an area**
  - Local area load forecast shows need for capacity expansion, or upgrades to meet reliability criteria
- **Develop distribution upgrade**
  - Preferred alternative is developed to solve the problem, minimum lifecycle revenue requirement
- **Establish capital budgeting plan**
  - Expected projects are compiled into a capital budgeting plan. Period of the plan depends on the utility, typically 5 to 10 years

Illustrative Project



Illustrative Project

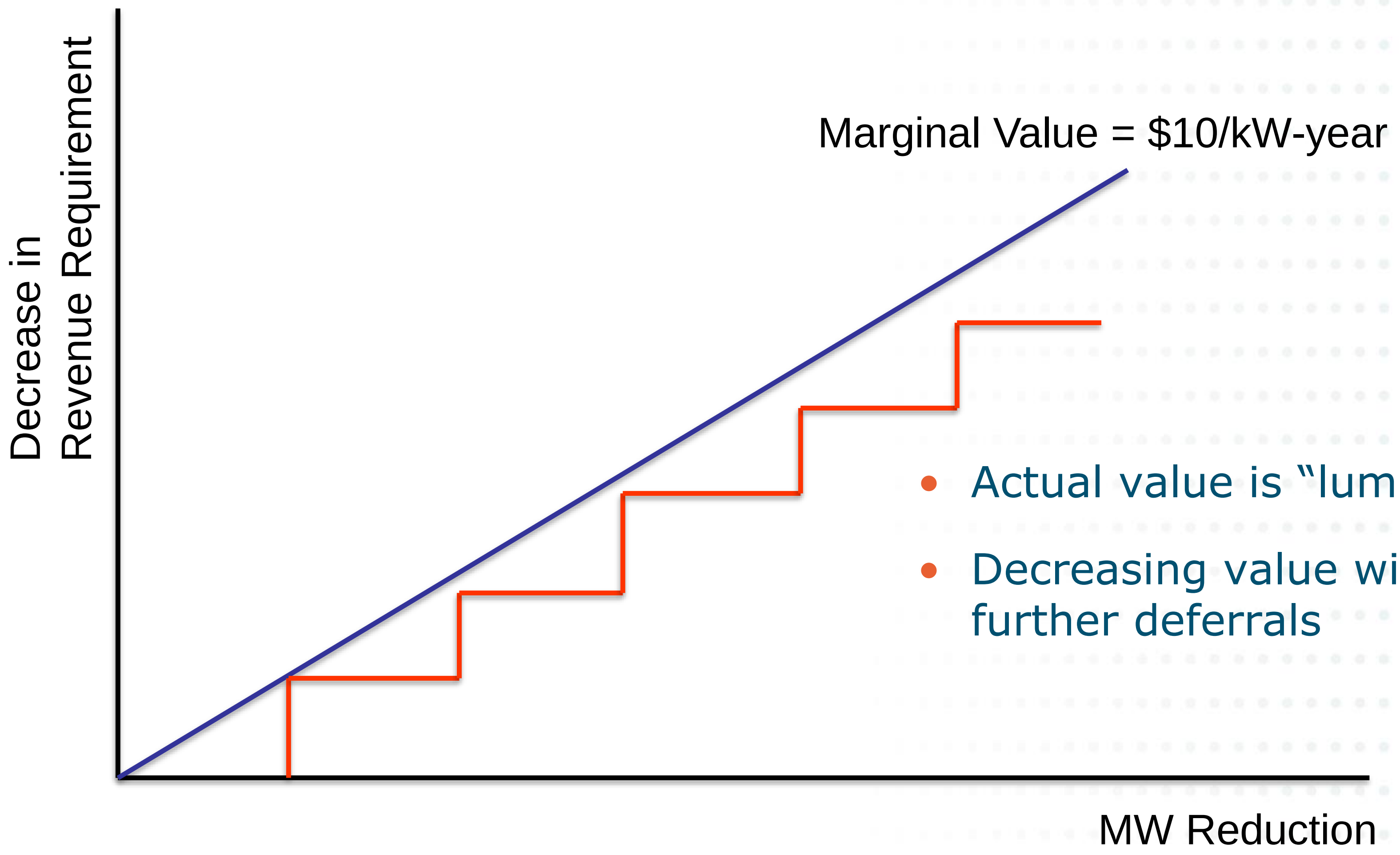


What Was Saved?

- **Original PV of revenue requirement (PVRR)**
  - \$10 million
- **Deferred PV of revenue requirement (PVRR)**
  - \$9 million
- **Savings of approximately**
  - \$1 million $= \$10 \text{ million} * \dfrac{(1+ 2\%)^2}{(1+ 7.5\%)^2}$
  - \$200/kW = \$1 million / 5,000kW
  - \$20/kW-year for 20 years = \$200/kW amortized over 20 years

Assumptions: Inflation = 2%, WACC = 7.5%

How does marginal compare with actual savings?



- Actual value is “lumpy”
- Decreasing value with further deferrals

What is Needed to Capture Value?

- **Distribution engineer feels confident in reliability when they actually delay the investment decision**
  - Sufficient peak load is reduced to defer the investment
  - Utility planning process accommodates embedded load

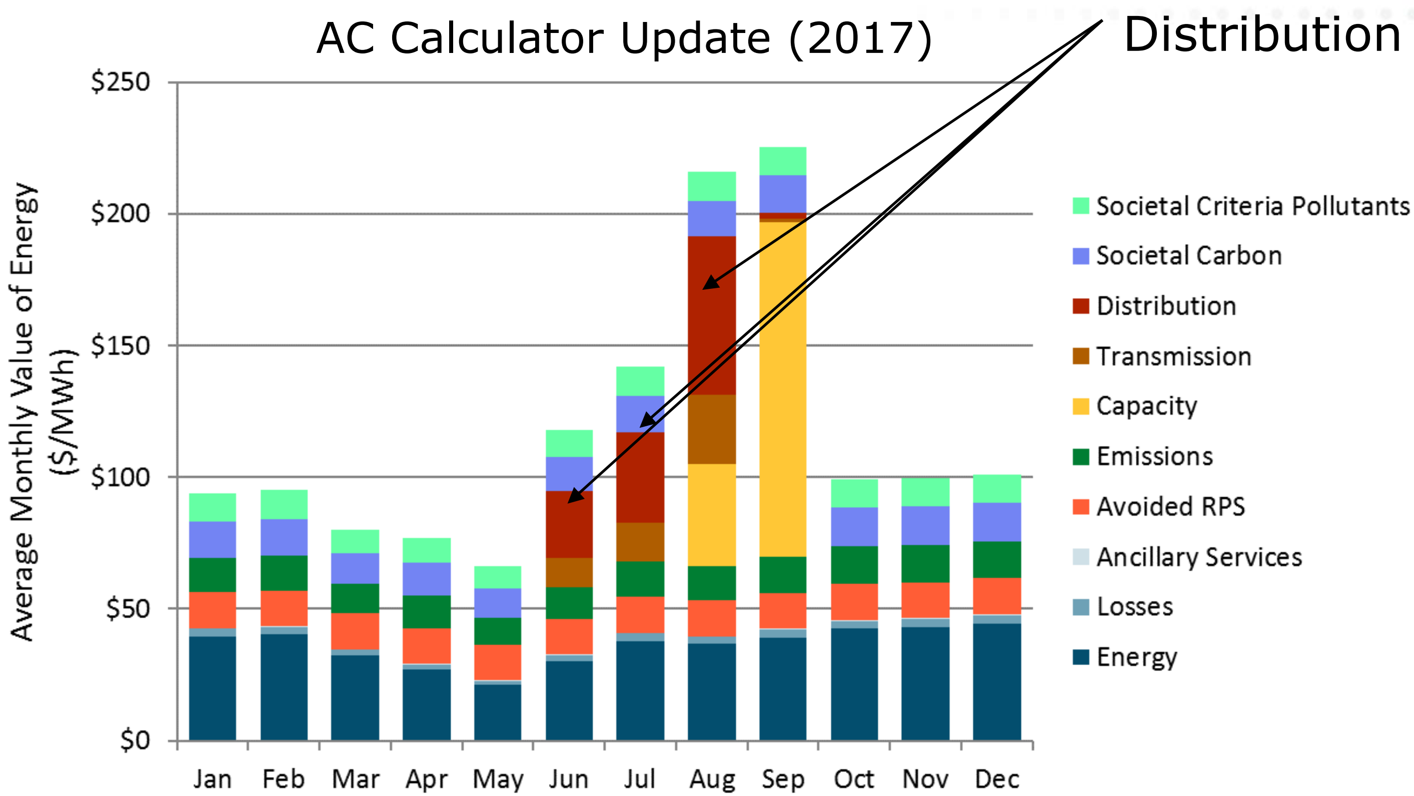
Implications for Contracting

- **There must be a minimum amount of load reduction must be achieved to defer an investment**
  - Non-wires solicitation, or pricing-based approaches that test marketplace for reduction strategies
- **Sufficient time to deploy non-wires solutions before distribution engineer implements alternative**
  - Extend the distribution planning horizon out to 5 to 10 years
- **Planned deferral is likely to be less time than the life of the renewable DG**
  - Make initial contract a fixed period, allow utility option to re-contract with DER
- **Early solicitations limit the near term flexibility and changing plans since contracts are entered earlier**

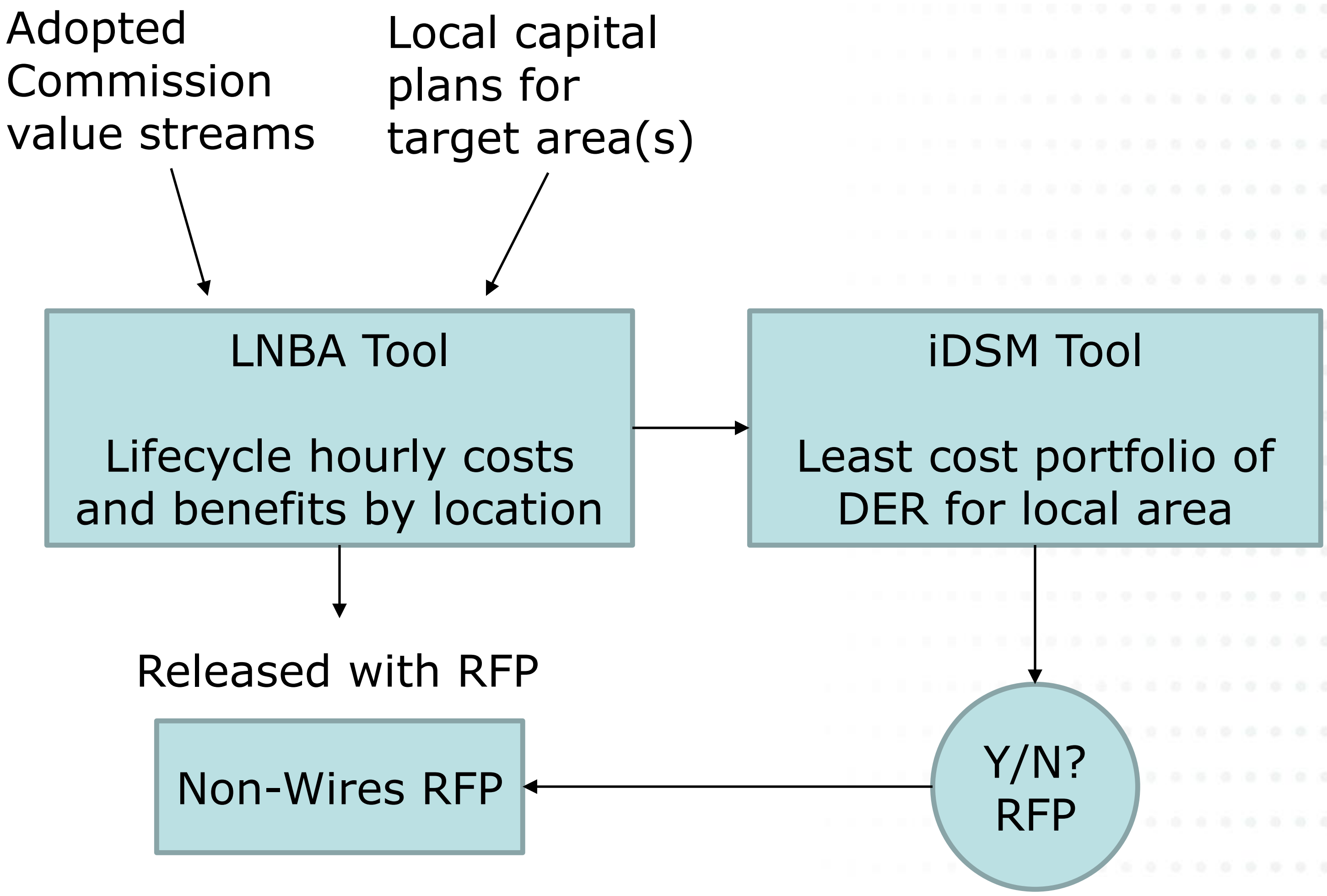
NEXT STEPS & DISCUSSION

Disaggregate Value by DPA in California Avoided Cost Update

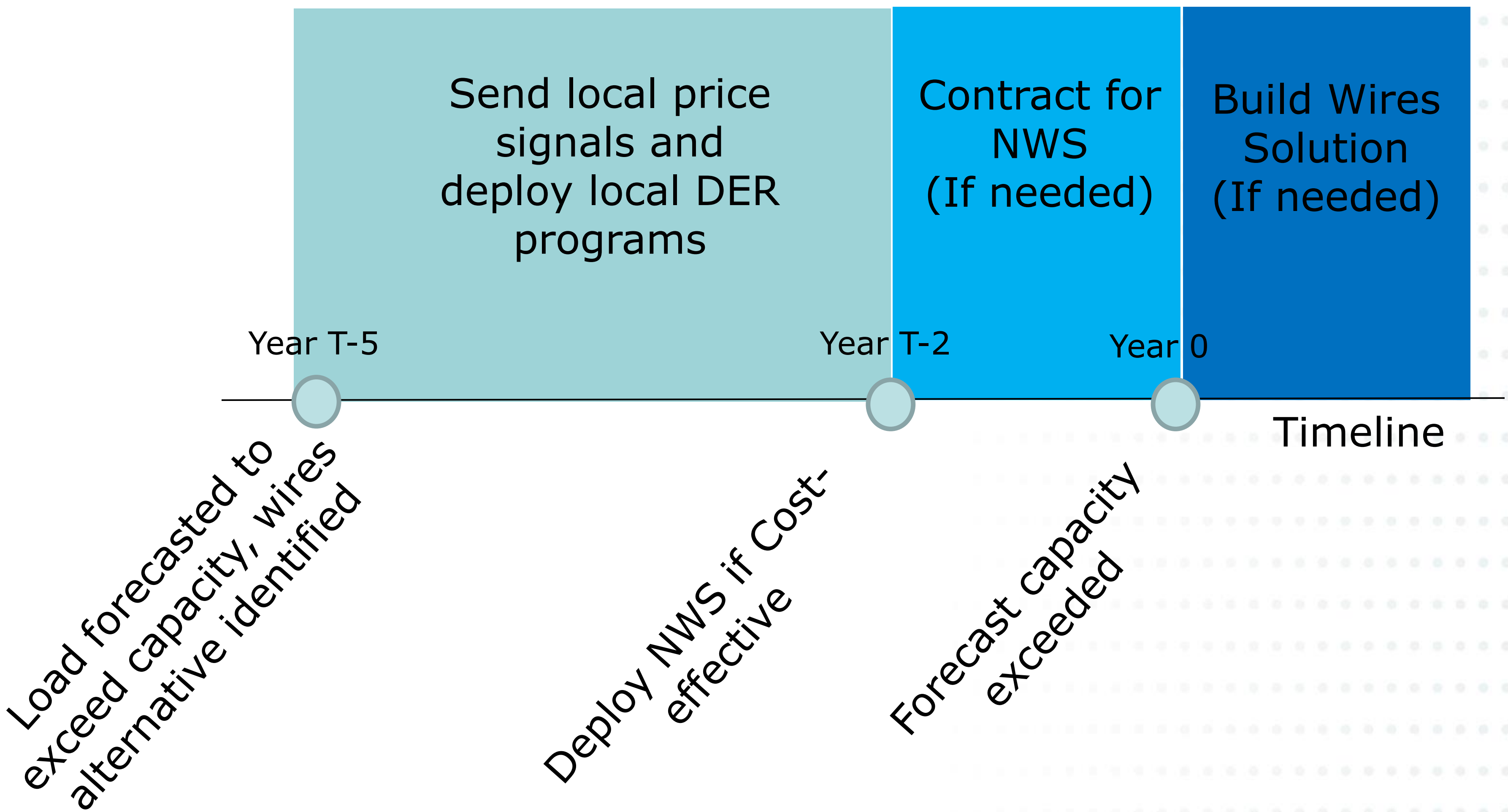
- Target Release May 31, 2018 will be ~500 Local Zones though those with no value may be grouped
- Primary Uses are Demand Response, Storage, and the 2019 NEM 3.0 Analysis in California



Links to iDSM Tool Evaluation



Pricing Platform with Backstop



Thank You!

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