Silicon Valley Power TAC Presentation Overview

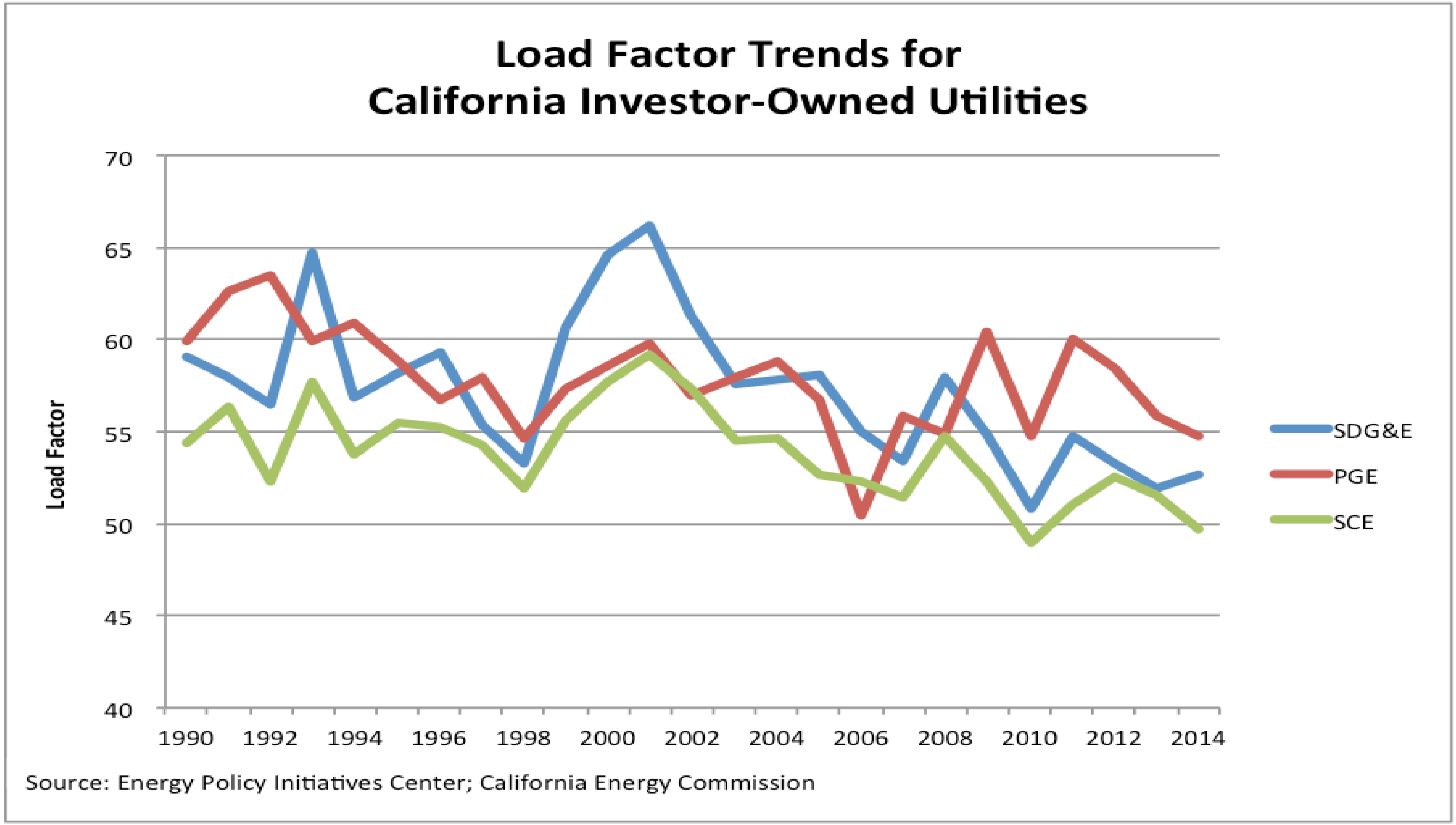
8/28/2017

Agenda

- Purpose of Silicon Valley Power's Comments
  - These initial comments offered by SVP are preliminary in nature, mainly intending to raise ideas for discussion and consideration, realizing that more technical analysis must yet be conducted.
- Volumetric Rates and Load Factor
- Transmission Built for Reliability vs. Load-Driven
- Exports and Hurdle Rates

Load Factor

- Annual Energy Use / (Peak Demand * 8760)



What does a declining Load Factor Mean?

- Essentially it means that volumetric usage (Annual MWhs) is decreasing faster than Peak usage (MWs).
- Is it really?
- It appears that *measured* volumetric usage is decreasing at a faster pace than peak usage, but a significant portion of this decreased measured volumetric usage is due to growth in behind the meter generation.

Is flow on Transmission Lines the best measure of the use/benefit they provide?

- Customers receive a benefit from the transmission system outside of a simple measurement of volumetric flow.
- The Transmission System is standing by to provide energy when needed, and this standby service is not accurately measured by volumetric flow.

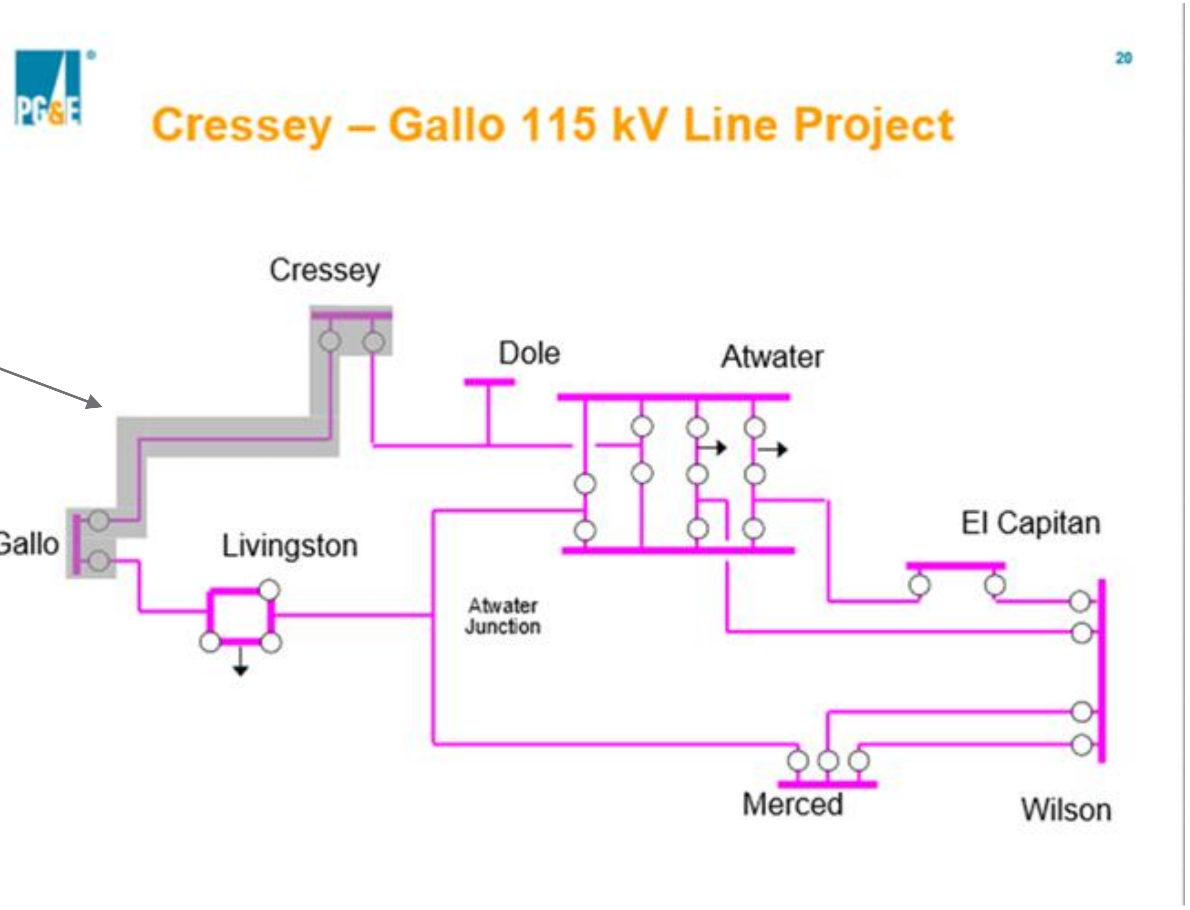
Transmission Planning Criteria/Design

- The Transmission System must be designed to meet peak demand
  - Much of the time transmission lines are only partially loaded, but are also standing by should they be needed.
  - A volumetric rate does not capture the standby nature of transmission service.
- In addition to simply designing the transmission system to ensure lines do not overload during times of system peaks the various transmission service providers also look at reliability of service from a benefit to cost ratio (BCR).

Reliability of Service Example (BCR) not Necessarily Reduced by DG

- PG&E Cressey Gallo 115 kV Line Project (14 Miles)

Proposed Project



Background

- Cressey, Gallo & Livingston Substations, located in the Northern Merced County, are served from the Atwater- Cressey and Atwater-Merced 115 kV radial Lines, respectively.
- Atwater Merced 115 kV Line has an average of approximately 2.3 outages per year, for roughly 7 hours per outage. Atwater Cressey 115 kv Line has an average of approximately 1 outage per year, of roughly 3.5 hours per outage.
- An Outage of Atwater Merced 115 kv Line (15 miles) results in sustained outages to Livingston and Gallo substations (6,100 customers, 30MW)
- An Outage of Atwater Cressey 115 kv Line (6 miles) results in sustained outages to Cressey and Dole substations (3,000 customers, 27MW)
- Project Scope: Build a new 14-mile 115 kV transmission line from Cressey Substation to Gallo Substation. Upgrade buses at Cressey and Gallo substations to loop arrangements.
- In-Service Date December 2015 Cost $15M - $20M
- Benefits of this project will improve reliability of electric service for PG&E customers in Cressey, Gallo and Livingston areas The PG&E BCR is 2.1

Benefit Cost Ratio (BCR) – CAISO Planning Standards

- Information Required for BCR calculation: For each of the outages that required involuntary interruption of load, the following should be estimated:
  - The maximum amount of load that would need to be interrupted.
  - The duration of the interruption.
  - The annual energy that would not be served or delivered.
  - The number of interruptions per year.
  - The time of occurrence of the interruption (e.g., week day summer afternoon).
  - The number of customers that would be interrupted.
  - The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural).
  - Value of service or performance-based ratemaking assumptions concerning the dollar impact of a load interruption.
- The above information will be documented in the ISO Transmission Plan for areas where additional transmission reinforcement is needed or justified through benefit to cost ratio determination.

Silicon Valley Power. City of Santa Clara

E. & J. Gallo Winery 2 MW Solar Facility (DG)

Livingston Neighborhood Rooftop Solar

SILICON VALLEY POWER.
CITY OF SANTA CLARA

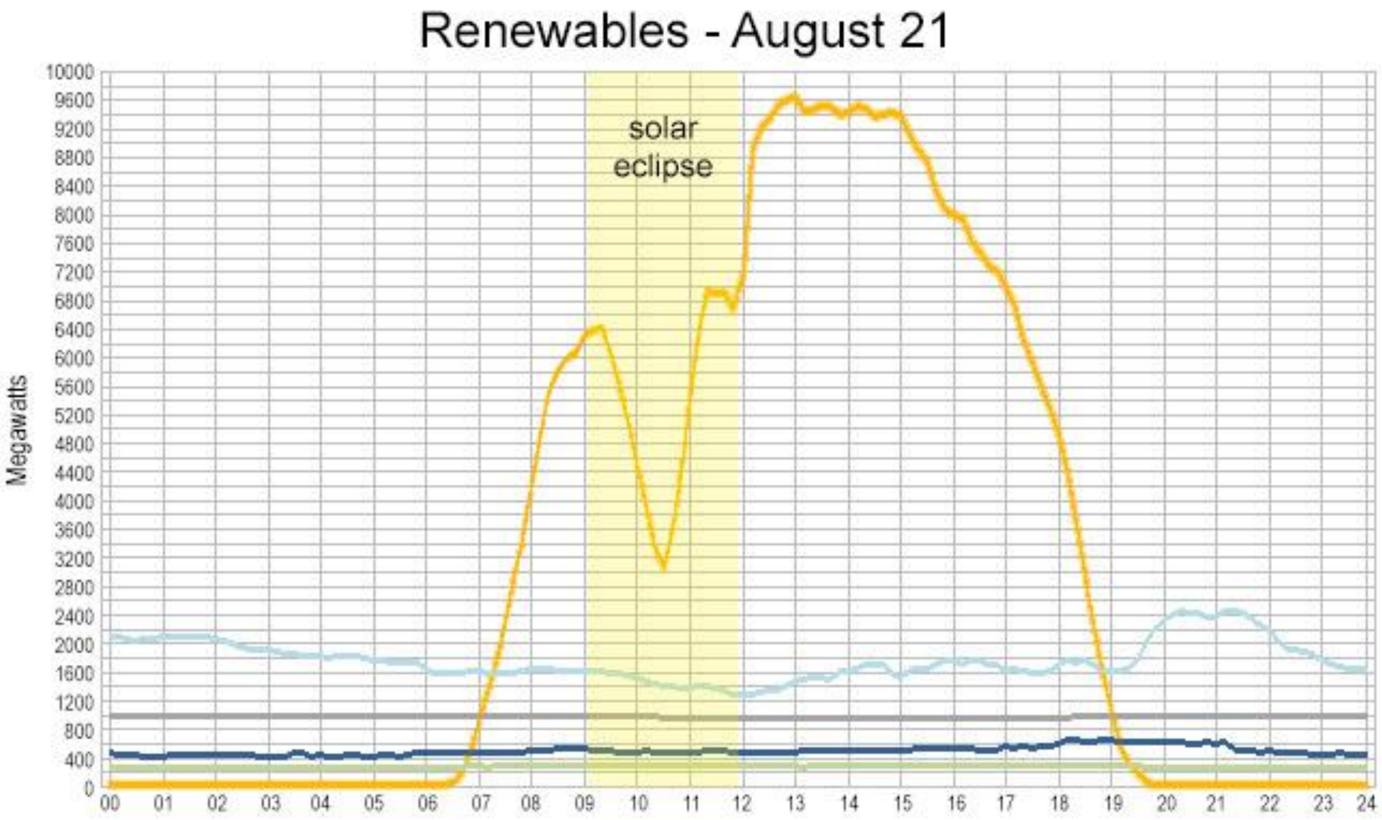
Relationship of DG to These types of Transmission Projects

- Output from the DG projects in this area does not eliminate the need for the Cressey – Gallo 115 kV project.
- Output of DG projects either behind the meter, or TED results in lower transmission costs paid by the specific customer or the UDC that serves these customer(s) even though the transmission project was designed to benefit specific customers by avoiding outages. (SVP is not sure how or if projects like the Gallo PV system are added to the current Gross Load TAC billing determinant)
- The PG&E TRR increases when projects such as the Cressey – Gallo line are built.
- All customers including those with DG in this area benefit from the project by the reduction in outages.
- Denominator that is used to determine the TAC rate decreases because measured volumetric demand in the local area has decreased from the buildout of DG.
- Who actually pays is determined by UDC, MSS, and LSE retail rate designs, and the amount of TAC charges each of these entities are allocated from the CAISO.

Silicon Valley Power
CITY OF SANTA CLARA

Transmission Provides Standby Access to Alternative Resources

Transmission allows for access to alternate resources, though the actual total energy during such periods may be small.

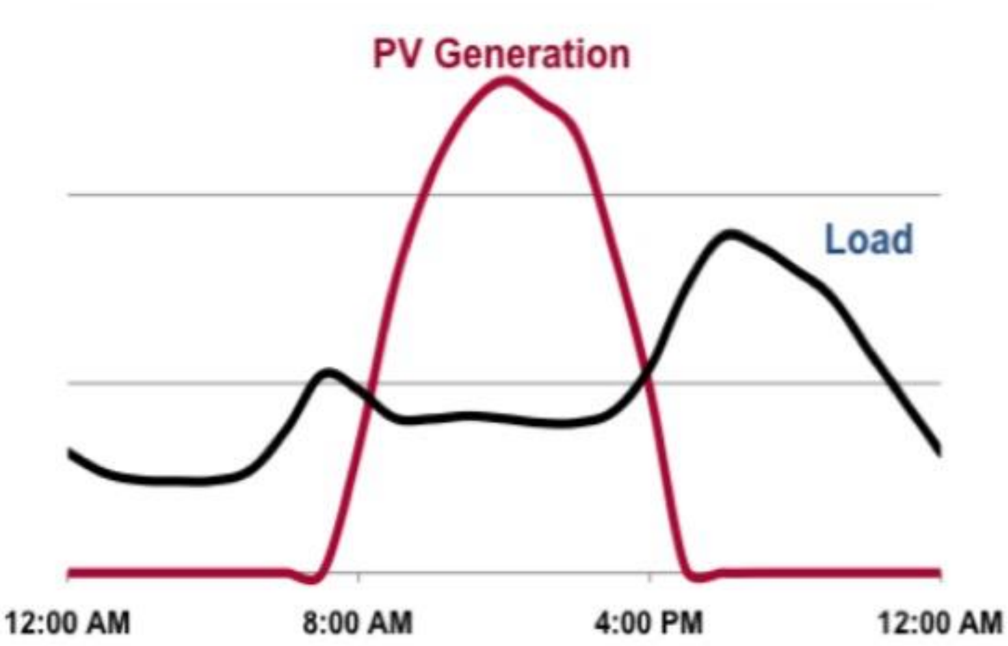


(While this graph reflects renewable in front of the meter, similar impact on behind the meter resources is expected.)

SILICON VALLEY POWER. CITY OF SANTA CLARA

Increased BTM Generation Does Not Necessarily Equate to Reduced Transmission Demands

While additional behind-the-meter generation may reduce the volumetric flow of energy through the transmission system, there becomes a threshold where the addition of such generation does not reduce the maximum demand on the transmission system



TAC Billing Determinants

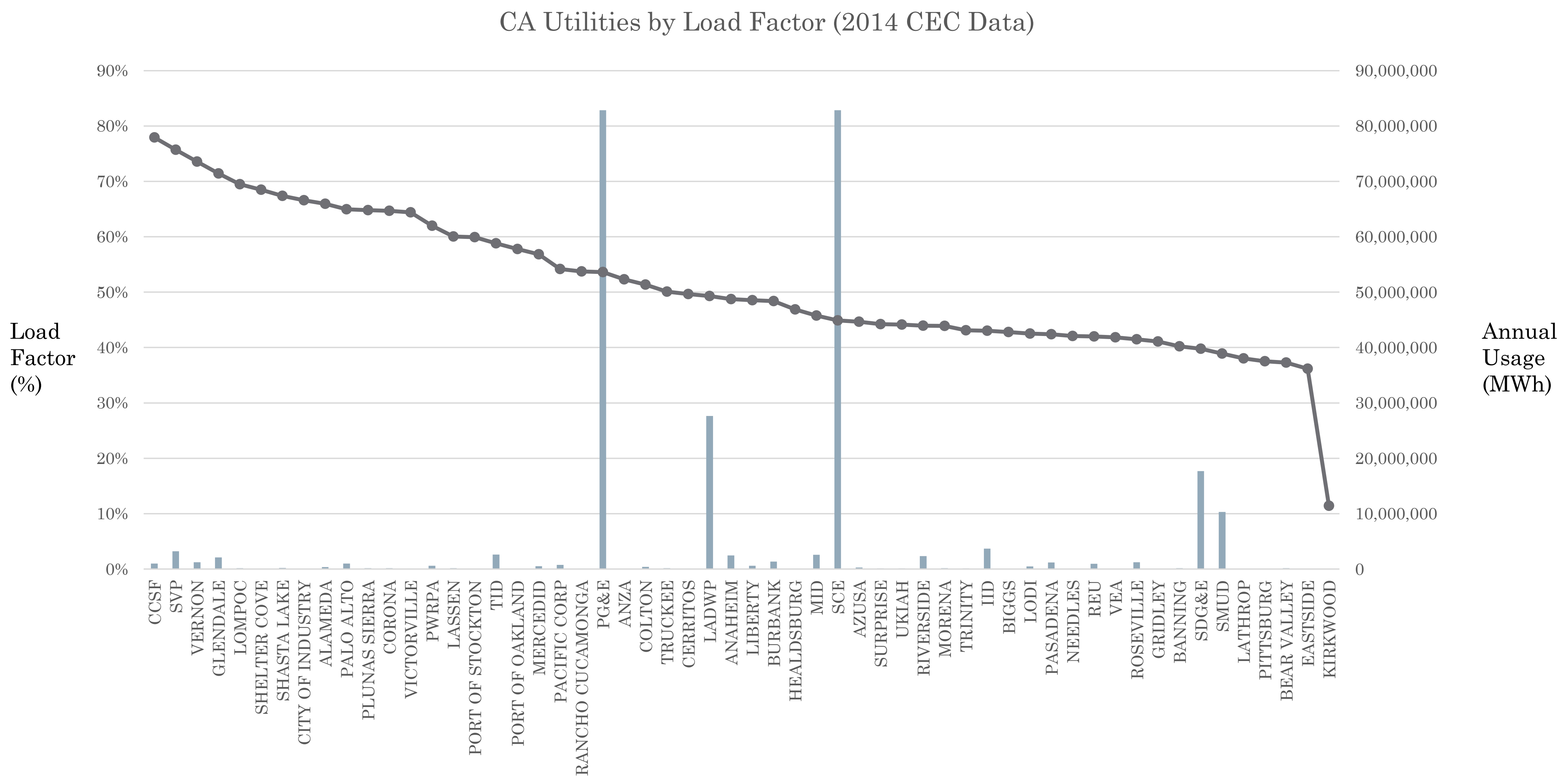
- Prior slides demonstrate that reduced volumetric demand attributable to DG does not necessarily reflect reduced reliance on transmission for reliability and does not result in lower transmission costs.
- Are there other billing determinants that more appropriately allocate certain transmission costs?
- Meters measure MWh, MW, and time.
- Is there anything else other than these three variables that should be explored for potential future use?

Review of California Utility Load Factors

- Load Factor affects how a utility would potentially be impacted by changing from using a purely volumetric charge to a methodology that includes using instantaneous demand-based charges

CEC 2014 Load Factor Data Statewide (Includes Utilities not in the CAISO)

LSE	Peak (MW)	Annual MWh	Load Factor	LSE	Peak (MW)	Annual MWh	Load Factor	LSE	Peak (MW)	Annual MWh	Load Factor
CCSF	144	983000	78%	PACIFIC CORP	161	764000	54%	TRINITY	27	102000	43%
SVP	482	3196000	76%	RANCHO CUCAMONGA	17	80000	54%	IID	982	3700000	43%
VERNON	191	1231000	74%	PG&E	17638	82840000	54%	BIGGS	4	15000	43%
GLENDALE	337	2109000	71%	ANZA	12	55000	52%	LODI	123	458000	43%
LOMPOC	23	140000	69%	COLTON	84	378000	51%	PASADENA	316	1174000	42%
SHELTER COVE	1	6000	68%	TRUCKEE	36	158000	50%	NEEDLES	16	59000	42%
SHASTA LAKE	31	183000	67%	CERRITOS	20	87000	50%	REU	262	964000	42%
CITY OF INDUSTRY	6	35000	67%	LADWP	6396	27628000	49%	VEA	3	11000	42%
ALAMEDA	63	364000	66%	ANAHEIM	578	2467000	49%	ROSEVILLE	340	1236000	41%
PALO ALTO	172	979000	65%	LIBERTY	139	591000	49%	GRIDLEY	10	36000	41%
PLUNAS SIERRA	28	159000	65%	BURBANK	314	1331000	48%	BANNING	42	148000	40%
CORONA	27	153000	65%	HEALDSBURG	19	78000	47%	SDG&E	5070	17672000	40%
VICTORVILLE	14	79000	64%	MID	642	2574000	46%	SMUD	3027	10319000	39%
PWRPA	109	592000	62%	SCE	21070	82849000	45%	LATHROP	0.3	1000	38%
LASSEN	27	142000	60%	AZUSA	69	270000	45%	PITTSBURG	7	23000	38%
PORT OF STOCKTON	4	21000	60%	SURPRISE	32	124000	44%	BEAR VALLEY	45	147000	37%
TID	510	2628000	59%	UKIAH	30	116000	44%	EASTSIDE	6	19000	36%
PORT OF OAKLAND	16	81000	58%	RIVERSIDE	604	2324000	44%	KIRKWOOD	3	3000	11%
MERCEDID	99	493000	57%	MORENA	39	150000	44%				



SILICON VALLEY POWER.
CITY OF SANTA CLARA

How Various Utilities Would be Impacted by a Change in TAC Billing Determinants – to a Methodology that Includes a Demand Component.

- Hypothetical base assumptions
  - All CA Utilities are in the CAISO
  - Looking at only a Regional Access Charge (HV) for simplicity.
  - Assumed HV TRR of $2,500,000,000
  - Uses CEC 2014 Data for Annual Demand and Peak Load
    - This data came from the legend of a map the CEC distributed, and SVP has not verified the accuracy for any Utilities other than itself.

Possible TAC Billing Determinant Scenarios*

- Existing Mechanism: Volumetric Only
  - $2,500,000,000 (Annual HV TRR) / 254,525,000 MWh (Annual Gross Load)
    - HV TAC = $9.82/MWh
- 50/50 split of TRR collected by peak demand and annual energy
  - $1,250,000,000 / 254,525,000 MWh
    - Volumetric TAC = $4.91/MWh,
  - $1,250,000,000 / 60,467.3 MW
    - Demand Charge = $20,672.33 MW-Year
- Peak Demand Only
  - $2,500,000,000 / 60,467.3 MW
    - Demand Charge = $41,344.66 / MW-Year

* Calculations use data from 2014 CEC values and assumptions on previous slide

How Would California Utilities Be Affected By Such A Change in TAC Billing Determinants?

- The following slides show a load factor for each California LSE and the resulting change in overall cost allocation

Utility	Peak Demand	Annual Energy	Load Factor	Volumetric Only	50/50 Volumetric/Peak Demand	% Change	100 % Demand	% Change
CCSF	144	983,000	77.9%	$ 9,655,240.15	$ 7,804,436	-19%	$ 5,953,631	-38%
SVP	482	3,196,000	75.7%	$ 31,391,808.27	$ 25,659,967	-18%	$ 19,928,126	-37%
VERNON	191	1,231,000	73.6%	$ 12,091,150.18	$ 9,993,990	-17%	$ 7,896,830	-35%
GLENDALE	337	2,109,000	71.4%	$ 20,715,057.46	$ 17,324,104	-16%	$ 13,933,151	-33%
LOMPOC	23	140,000	69.5%	$ 1,375,110.50	$ 1,163,019	-15%	$ 950,927	-31%
SHELTER COVE	1	6,000	68.5%	$ 58,933.31	$ 50,139	-15%	$ 41,345	-30%
SHASTA LAKE	31	183,000	67.4%	$ 1,797,465.87	$ 1,539,575	-14%	$ 1,281,684	-29%
CITY OF INDUSTRY	6	35,000	66.6%	$ 343,777.62	$ 295,923	-14%	$ 248,068	-28%
ALAMEDA	63	364,000	66.0%	$ 3,575,287.30	$ 3,090,000	-14%	$ 2,604,714	-27%
PALO ALTO	172	979,000	65.0%	$ 9,615,951.28	$ 8,363,616	-13%	$ 7,111,282	-26%
PLUNAS SIERRA	28	159,000	64.8%	$ 1,561,732.64	$ 1,359,692	-13%	$ 1,157,650	-26%
CORONA	27	153,000	64.7%	$ 1,502,799.33	$ 1,309,553	-13%	$ 1,116,306	-26%
VICTORVILLE	14	79,000	64.4%	$ 775,955.21	$ 677,390	-13%	$ 578,825	-25%
PWRPA	109	592,000	62.0%	$ 5,814,752.97	$ 5,160,660	-11%	$ 4,506,568	-22%
LASSEN	27	142,000	60.0%	$ 1,394,754.94	$ 1,255,530	-10%	$ 1,116,306	-20%
PORT OF STOCKTON	4	21,000	59.9%	$ 206,266.57	$ 185,823	-10%	$ 165,379	-20%
TID	510	2,628,000	58.8%	$ 25,812,788.53	$ 23,449,283	-9%	$ 21,085,777	-18%
PORT OF OAKLAND	16	81,000	57.8%	$ 795,599.65	$ 728,557	-8%	$ 661,515	-17%
MERCEDID	99	493,000	56.8%	$ 4,842,353.40	$ 4,467,737	-8%	$ 4,093,121	-15%
PACIFIC CORP	161	764,000	54.2%	$ 7,504,174.44	$ 7,080,332	-6%	$ 6,656,490	-11%
RANCHO CUCAMONGA	17	80,000	53.7%	$ 785,777.43	$ 744,318	-5%	$ 702,859	-11%
PG&E	17,638	82,840,000	53.6%	$ 813,672,527.26	$ 771,454,826	-5%	$ 729,237,125	-10%
ANZA	12	55,000	52.3%	$ 540,221.98	$ 518,179	-4%	$ 496,136	-8%
COLTON	84	378,000	51.4%	$ 3,712,798.35	$ 3,592,875	-3%	$ 3,472,951	-6%
TRUCKEE	36	158,000	50.1%	$ 1,551,910.42	$ 1,520,159	-2%	$ 1,488,408	-4%
CERRITOS	20	87,000	49.7%	$ 854,532.95	$ 840,713	-2%	$ 826,893	-3%
LADWP	6,396	27,628,000	49.3%	$ 271,368,234.95	$ 267,904,342	-1%	$ 264,440,450	-3%
ANAHEIM	578	2,467,000	48.7%	$ 24,231,411.45	$ 24,064,313	-1%	$ 23,897,214	-1%

Utility	Peak Demand	Annual Energy	Load Factor	Volumetric Only	50/50 Volumetric/Peak Demand	% Change	100 % Demand	% Change
LIBERTY	139	591,000	48.5%	$ 5,804,930.75	$ 5,775,919	0%	$ 5,746,908	-1%
BURBANK	314	1,331,000	48.4%	$ 13,073,371.97	$ 13,027,798	0%	$ 12,982,223	-1%
HEALDSBURG	19	78,000	46.9%	$ 766,132.99	$ 775,841	1%	$ 785,549	3%
MID	642	2,574,000	45.8%	$ 25,282,388.76	$ 25,912,830	2%	$ 26,543,272	5%
SCE	21,070	82,849,000	44.9%	$ 813,760,927.22	$ 842,446,464	4%	$ 871,132,000	7%
AZUSA	69	270,000	44.7%	$ 2,651,998.82	$ 2,752,390	4%	$ 2,852,782	8%
SURPRISE	32	124,000	44.2%	$ 1,217,955.01	$ 1,270,492	4%	$ 1,323,029	9%
UKIAH	30	116,000	44.1%	$ 1,139,377.27	$ 1,189,859	4%	$ 1,240,340	9%
RIVERSIDE	604	2,324,000	43.9%	$ 22,826,834.30	$ 23,899,505	5%	$ 24,972,175	9%
MORENA	39	150,000	43.9%	$ 1,473,332.68	$ 1,542,887	5%	$ 1,612,442	9%
TRINITY	27	102,000	43.1%	$ 1,001,866.22	$ 1,059,086	6%	$ 1,116,306	11%
IID	982	3,700,000	43.0%	$ 36,342,206.07	$ 38,471,331	6%	$ 40,600,457	12%
BIGGS	4	15,000	42.8%	$ 147,333.27	$ 156,356	6%	$ 165,379	12%
LODI	123	458,000	42.5%	$ 4,498,575.78	$ 4,791,985	7%	$ 5,085,393	13%
PASADENA	316	1,174,000	42.4%	$ 11,531,283.76	$ 12,298,098	7%	$ 13,064,913	13%
NEEDLES	16	59,000	42.1%	$ 579,510.85	$ 620,513	7%	$ 661,515	14%
REU	262	964,000	42.0%	$ 9,468,618.01	$ 10,150,460	7%	$ 10,832,301	14%
VEA	3	11,000	41.9%	$ 108,044.40	$ 116,039	7%	$ 124,034	15%
ROSEVILLE	340	1,236,000	41.5%	$ 12,140,261.27	$ 13,098,723	8%	$ 14,057,185	16%
GRIDLEY	10	36,000	41.1%	$ 353,599.84	$ 383,523	8%	$ 413,447	17%
BANNING	42	148,000	40.2%	$ 1,453,688.24	$ 1,595,082	10%	$ 1,736,476	19%
SDG&E	5,070	17,672,000	39.8%	$ 173,578,233.97	$ 191,597,832	10%	$ 209,617,430	21%
SMUD	3,027	10,319,000	38.9%	$ 101,355,466.06	$ 113,252,877	12%	$ 125,150,288	23%
LATHROP	0.3	1,000	38.1%	$ 9,822.22	$ 11,113	13%	$ 12,403	26%
PITTSBURG	7	23,000	37.5%	$ 225,911.01	$ 257,662	14%	$ 289,413	28%
BEAR VALLEY	45	147,000	37.3%	$ 1,443,866.02	$ 1,652,188	14%	$ 1,860,510	29%
EASTSIDE	6	19,000	36.1%	$ 186,622.14	$ 217,345	16%	$ 248,068	33%
KIRKWOOD	3	3,000	11.4%	$ 29,466.65	$ 76,750	160%	$ 124,034	321%

Overall Conclusions

- Utilities with a Load Factor furthest from 48% (System Average Load Factor) are impacted the greatest by shifting to a portion of the TRR collected through a Demand Charge based on Peak Usage
- Low Load Factor Utilities Costs Increase, and High Load Factor Utilities Costs Decrease.
- Two ways of looking at this:
  - Some Utilities are going to have substantially different costs going forward and any changes need to be justified through analysis and application of sound cost causation principles.
  - Some Utilities have enjoyed a benefit, or paid substantially more, over than the past decade, and a change is merely a correction to a more just and reasonable allocation - now that the CAISO includes participants with greater disparity in Load Factor that may not have needed to be considered when a purely volumetric rate was adopted.

TAC and its Allocation to Exports

- Currently any market participant submitting bids or self schedules to export power must consider the TAC rate when making this economic decision.
- Regional TAC (HV) - $11.67/MWh
- Currently bidders for exports from the CAISO include this added marginal cost in their bid price.
- For Example during a spring run off situation when an entity in the Northwest may be in spill conditions with hydro generation a bid for energy from the CAISO may be at -$11.67/MWh less any other variable costs associated with moving the energy from the Scheduling Point to its System such as Transmission losses outside of the CAISO System, or additional transmission that would be needed to be procured through hourly transactions.

SILICON VALLEY POWER.
CITY OF SANTA CLARA

Impact during periods of High Solar and Hydro production

- Supply from Solar production is bid into the CAISO market typically around the market value of a loss associated with a PCC1 REC. When an RPS eligible renewable resources does not generate, the REC that could have been generated is lost. Bids from these types of resources currently are around -$15/MWh.

- In the Pacific Northwest during high river flow conditions the value of energy, (marginal production cost), from hydro resources drops to near $0/MWh, and it makes sense that they would prefer to purchase power if they can procure power below this marginal cost.

- Under a volumetric TAC rate that applies to Exports means the bids for energy from the CAISO system during these types of conditions would be slightly more negative than the applicable TAC rate.

What would change if Market Participants were not exposed to Volumetric Rates?

- Assuming transmission was available to be purchased under a different structure the current $11.67/MWh hurdle rate could be removed from an exporter's bid.

- Example:
  - A market participant could instead choose to make an election to pay for transmission under a long term contract, (Some MW quantity at $xx.xx /MW-year).
  - For awarded export bids of energy at or below this MW quantity the market participant is not exposed to the volumetric rate, and for quantities above this amount they would pay the applicable volumetric rate.
  - In this scenario the transmission cost for use of the CAISO grid is already sunk similar to other fixed expenses faced by generators that don't become part of their marginal cost bids of supply. (Debt Service, Fixed O&M, etc…)
  - Market Participants who chose not to pay for a demand based rate would still be exposed to a volumetric rate for any exports.

SILICON VALLEY POWER.
CITY OF SANTA CLARA

Potential End Results of Demand Based Transmission Rate for Exports

- Potential additional revenue stream for transmission that currently goes unused because of the market inefficiencies caused by the magnitude of the volumetric TAC rate – should result in less TRR to be collected from volumetric rates.
- Increased demand for midday solar when there isn't sufficient demand internal to the CAISO along with other generation that must be online to meet the morning and evening peak.
- Increased REC production in the event that the current rate design results in solar curtailments.
- Potential lessening of the morning and evening ramps.
- Potential decrease in BCR payments needed to be made by the CAISO.
- Greater ability for lower heat-rate thermal generation within the CAISO to displace less efficient thermal generation outside the CAISO.
- Lower GHG emissions throughout the West due to a more efficient market.

Silicon Valley Power. City of Santa Clara

Questions?