Clean Coalition

Local clean energy generation or remote — who wins the battle?

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Presenters

Bill Powers is a registered professional mechanical engineer in California and Missouri with over 35 years of experience in energy and environmental engineering.

Rao Konidena of Rakon Energy LLC is an independent consultant focused on providing policy and testimony support, business development, and training in wholesale energy markets.

Rosana Francescato is the Clean Coalition's Communications Director and leads the Transmission Access Charges (TAC) Campaign.

Mission

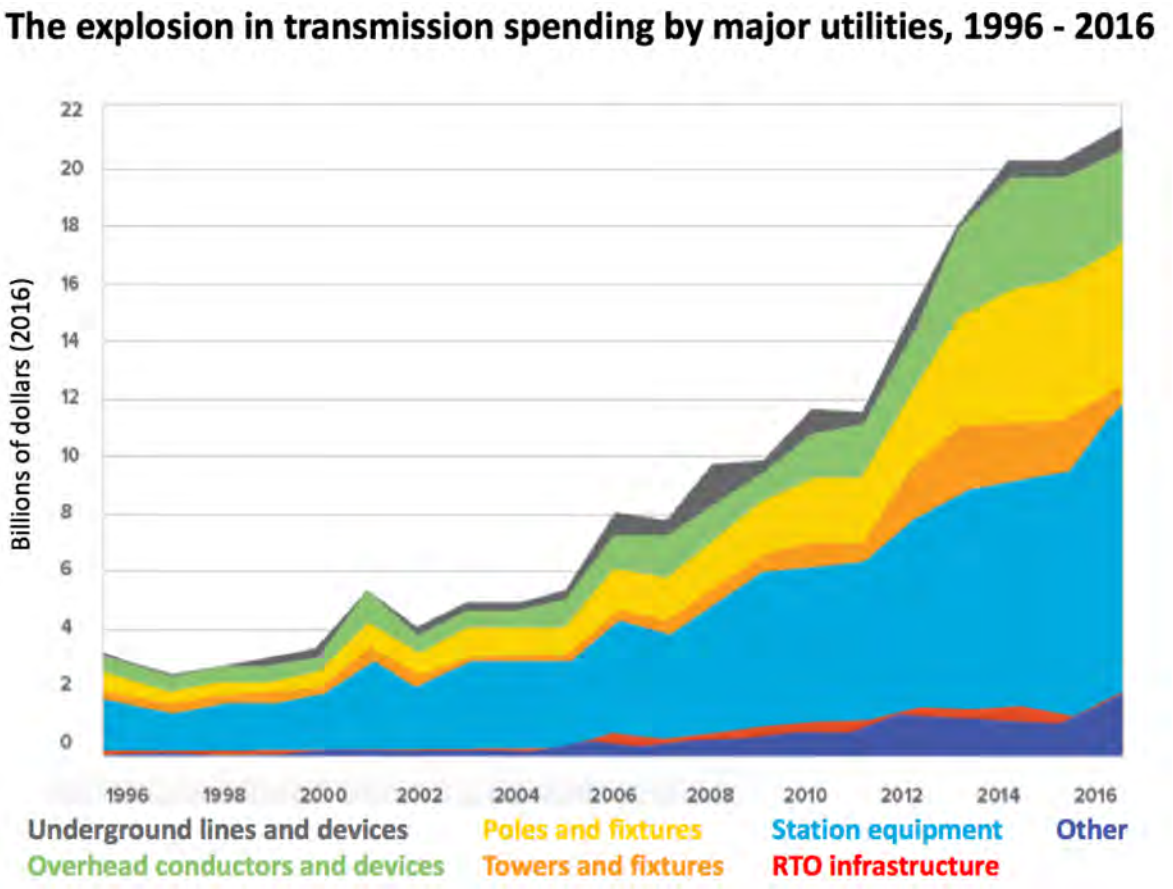
To accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise.

100% renewable energy end-game

- 25% local, interconnected within the distribution grid and facilitating resilience without dependence on the transmission grid.
- 75% remote, dependent on the transmission grid for serving loads.

Transmission costs are fastest-growing component of electricity costs

- Transmission costs are the fastest-growing component of your electricity bill.
- Guaranteed 12% return-on-equity (ROE) for transmission investments leads to conflicts of interest and perverse market outcomes.



Transmission costs higher than they seem due to O&M driving ~10x increase to upfront costs

- Capital costs of transmission infrastructure represent a fraction of total transmission costs.
- Operations and maintenance (O&M) and ROE drive up transmission costs significantly over asset lifetime, with those excessive costs borne by ratepayers.

Nominal costs

Asset value capital cost ($100 base)	$100
Return	$197
O&M	$631
Total nominal ratepayer cost per $100 investment (50 years)	**$928**

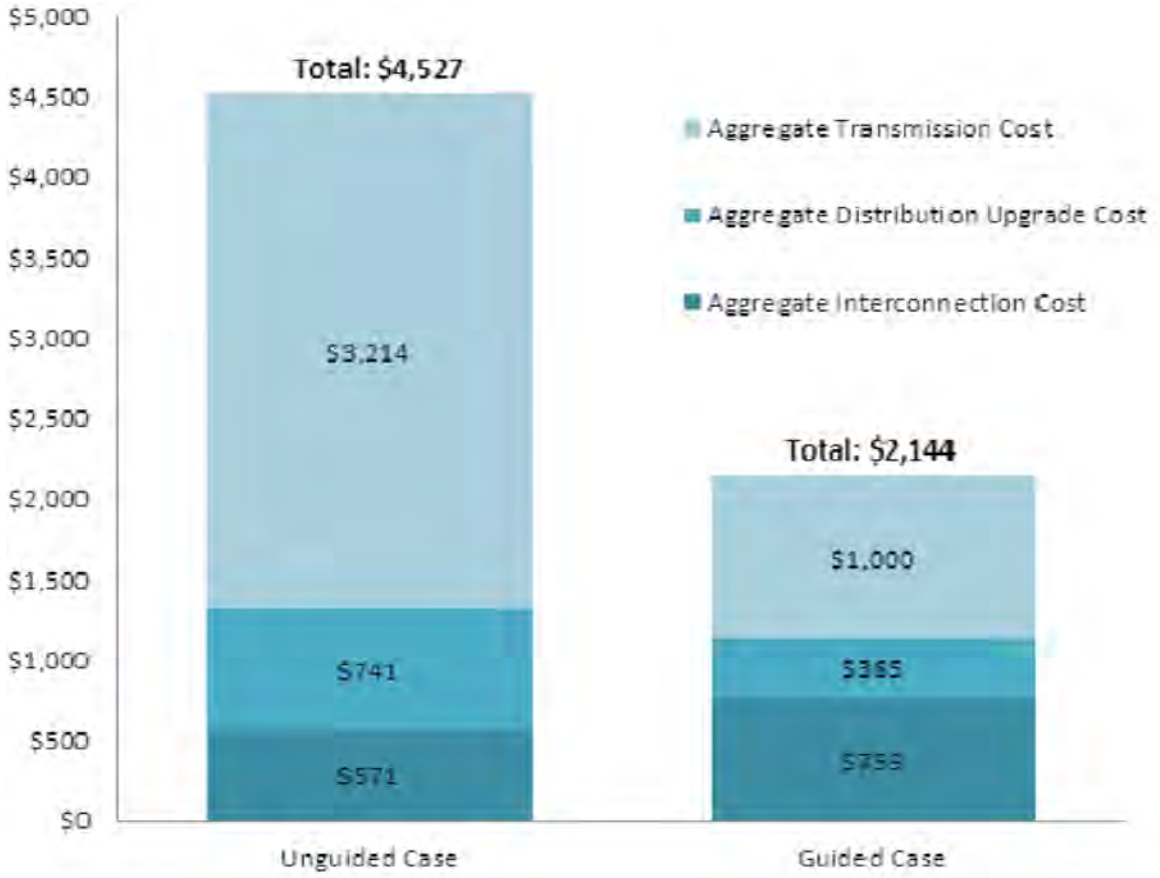
Real costs, discounted for inflation

Discount rate	2.19%
Asset value capital cost ($100 base)	$100
Return, discounted	$140
O&M, discounted	$296
Total discounted (real) ratepayer cost per $100 investment (50 years)	**$536**

In nominal dollars, total lifetime ratepayer cost is nearly 10x the initial capital cost; O&M accounts for 68% of this because it increases much faster than inflation. In real dollars (constant value dollars, accounting for inflation), the total lifetime cost is 5x the initial capital cost, and O&M accounts for 55% of this.

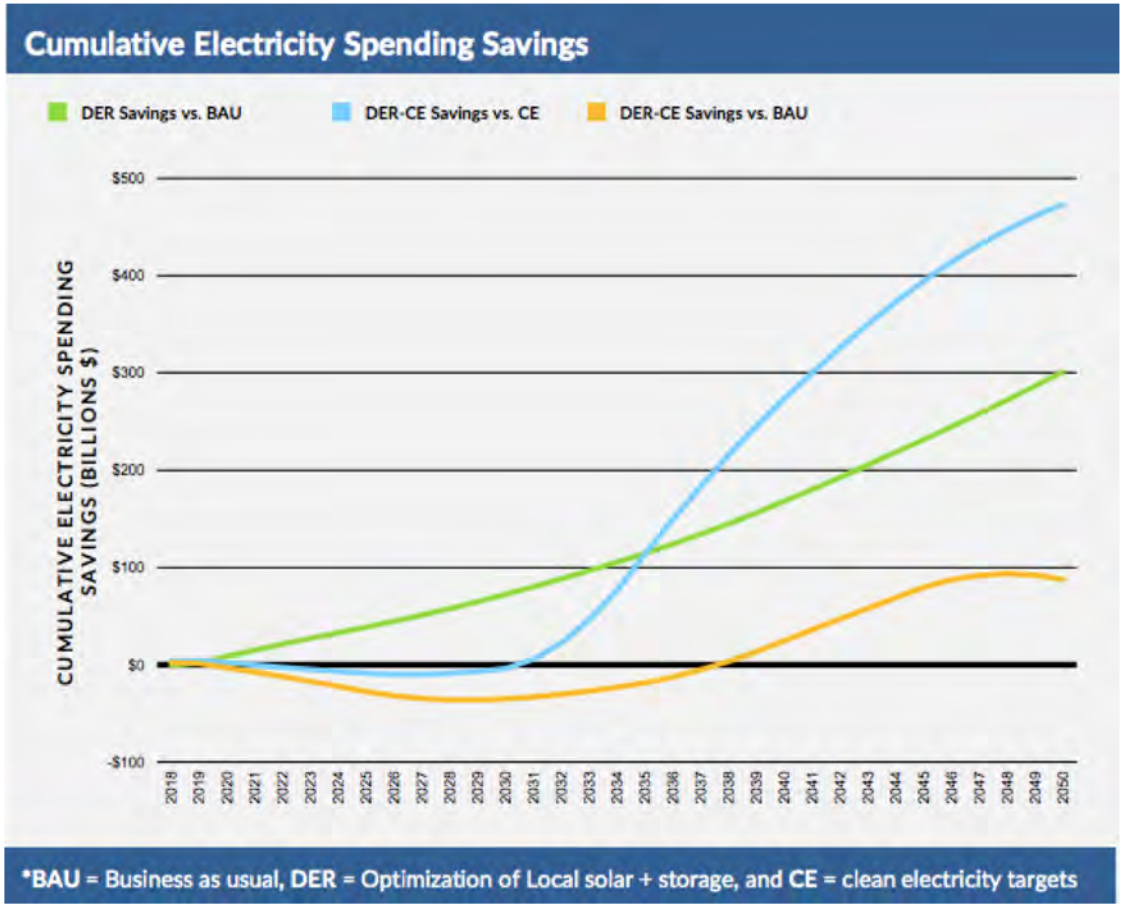
Local solar+storage optimize the grid for ratepayer savings

- Intelligently siting 4 GW of local solar would preempt over **$2.2 billion** in new transmission infrastructure investments — about **$20 billion** in ratepayer savings when considering O&M. (Southern California Edison study)
- Transmission costs are always borne by ratepayers, while distribution & interconnection costs are borne by solar project developers.



Local solar+storage optimize the grid for ratepayer savings

- Deploying enough large solar and wind farms to decrease CO2 emissions by 95% by 2050 would **cost Americans $385 billion more** for power over the next 30 years.
- Scaling up local solar+storage in coordination with utility-scale renewables, we can achieve the same clean-energy goals while **saving $473 billion**.



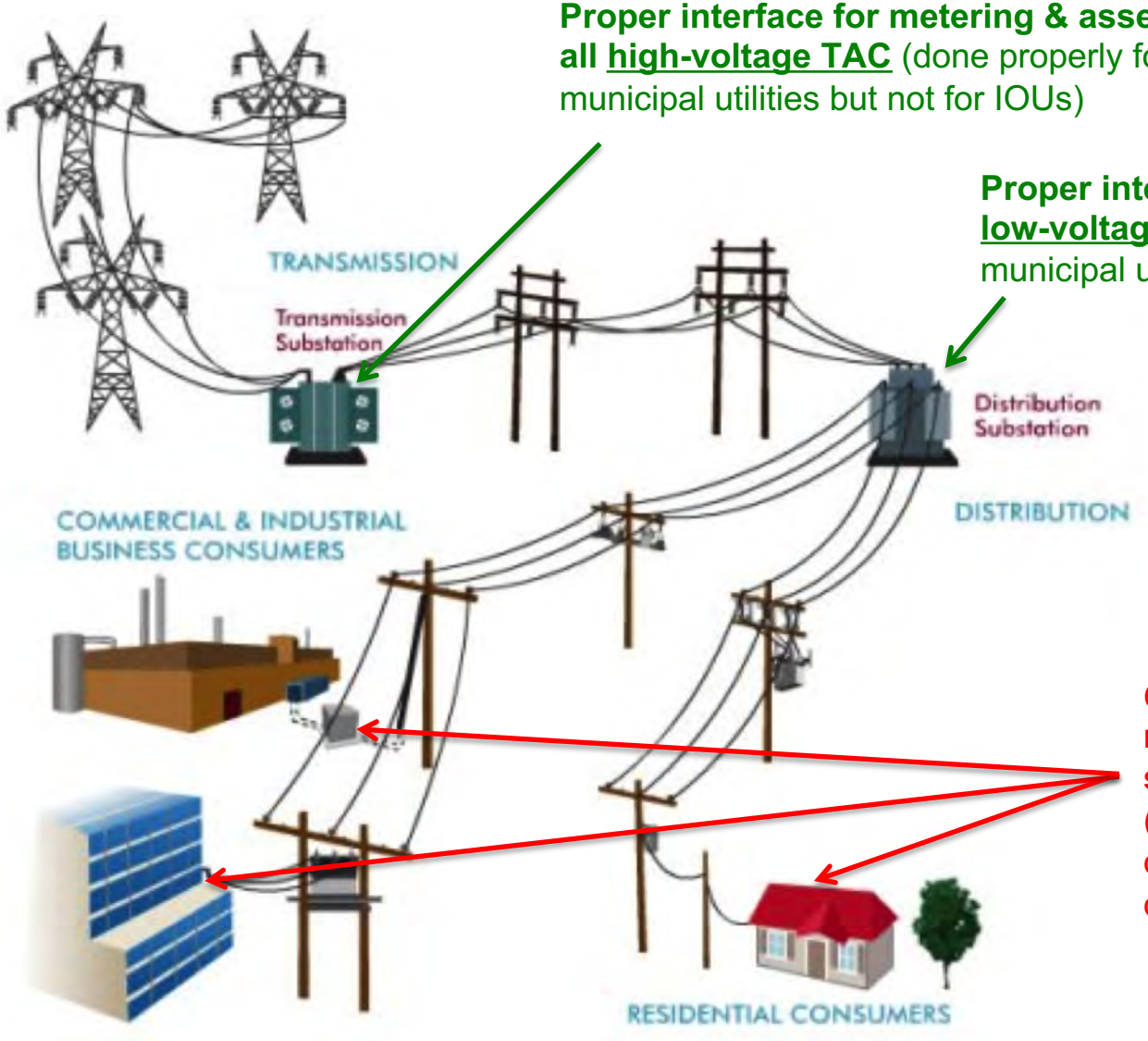
Source:
Vibrant Clean Energy

TAC cause massive market distortions — the real cost shift happening in California

Clean Coalition

Proper interface for metering & assessing all high-voltage TAC (done properly for municipal utilities but not for IOUs)

Proper interface for metering all low-voltage TAC (done properly for municipal utilities but not for IOUs)



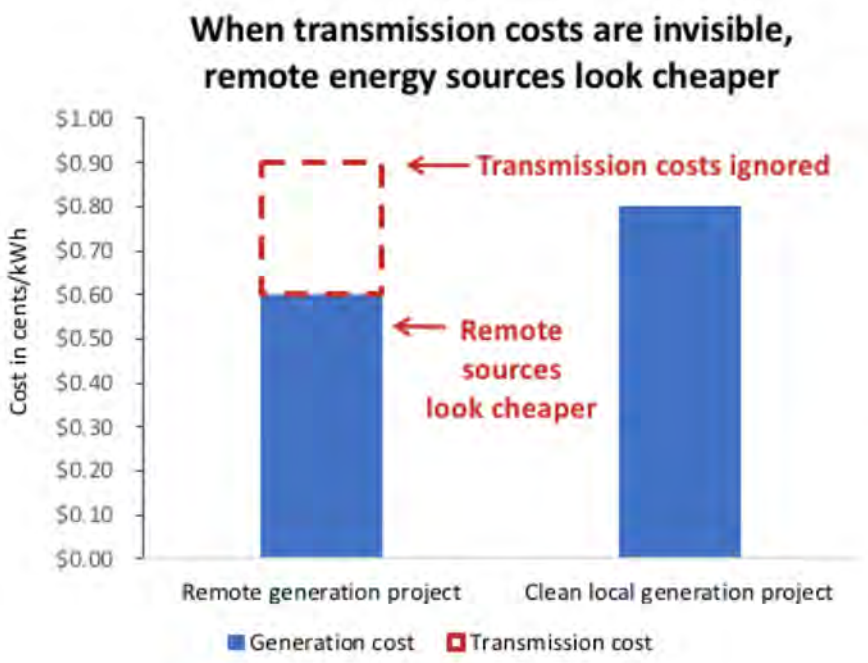
Current interface for metering TAC in IOU service territories (at customer meters, with no distinction of energy from next door vs 1,000 miles away)

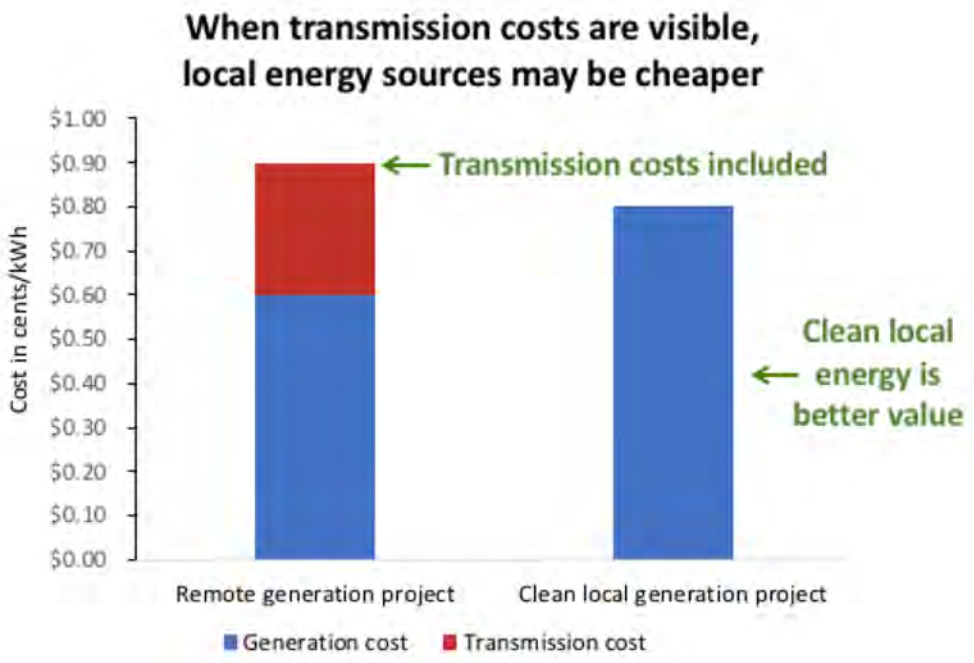
TAC market distortion: The real cost shift

- Transmission Access Charges (TAC) in California's IOU service territories are metered and assessed incorrectly, at the customer meter.
- That's like paying extra shipping & handling fees for something you pick up next door, or paying a toll if you don't cross a bridge.
- **This is the real cost shift happening in California**.

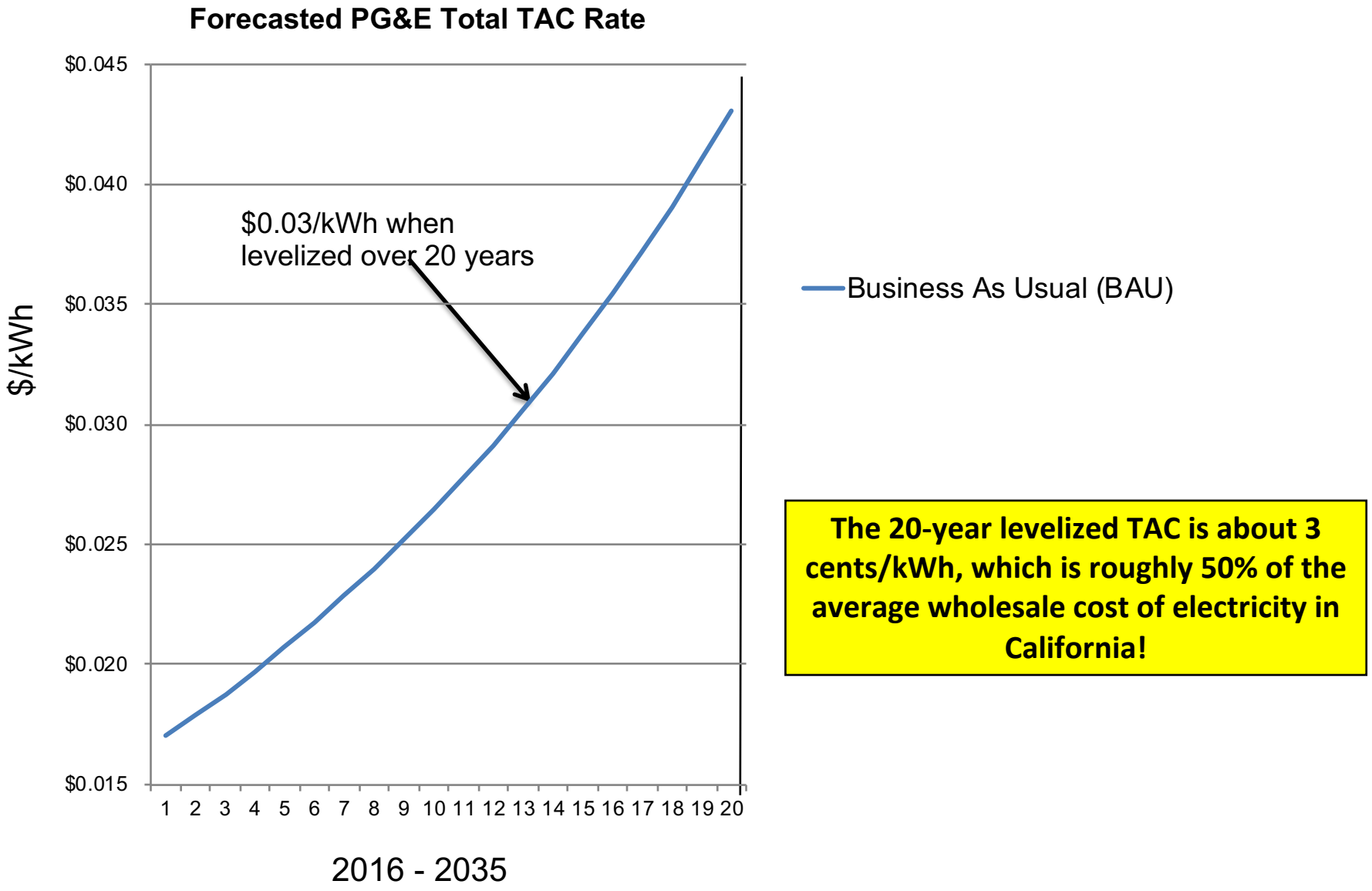
How the TAC market distortion cost shift makes local renewables look less cost-effective

- 3¢/kWh is being stolen from local renewables, making them look more expensive.
- Stealing funds from DER-driven Community Microgrids that deliver [community resilience](#).





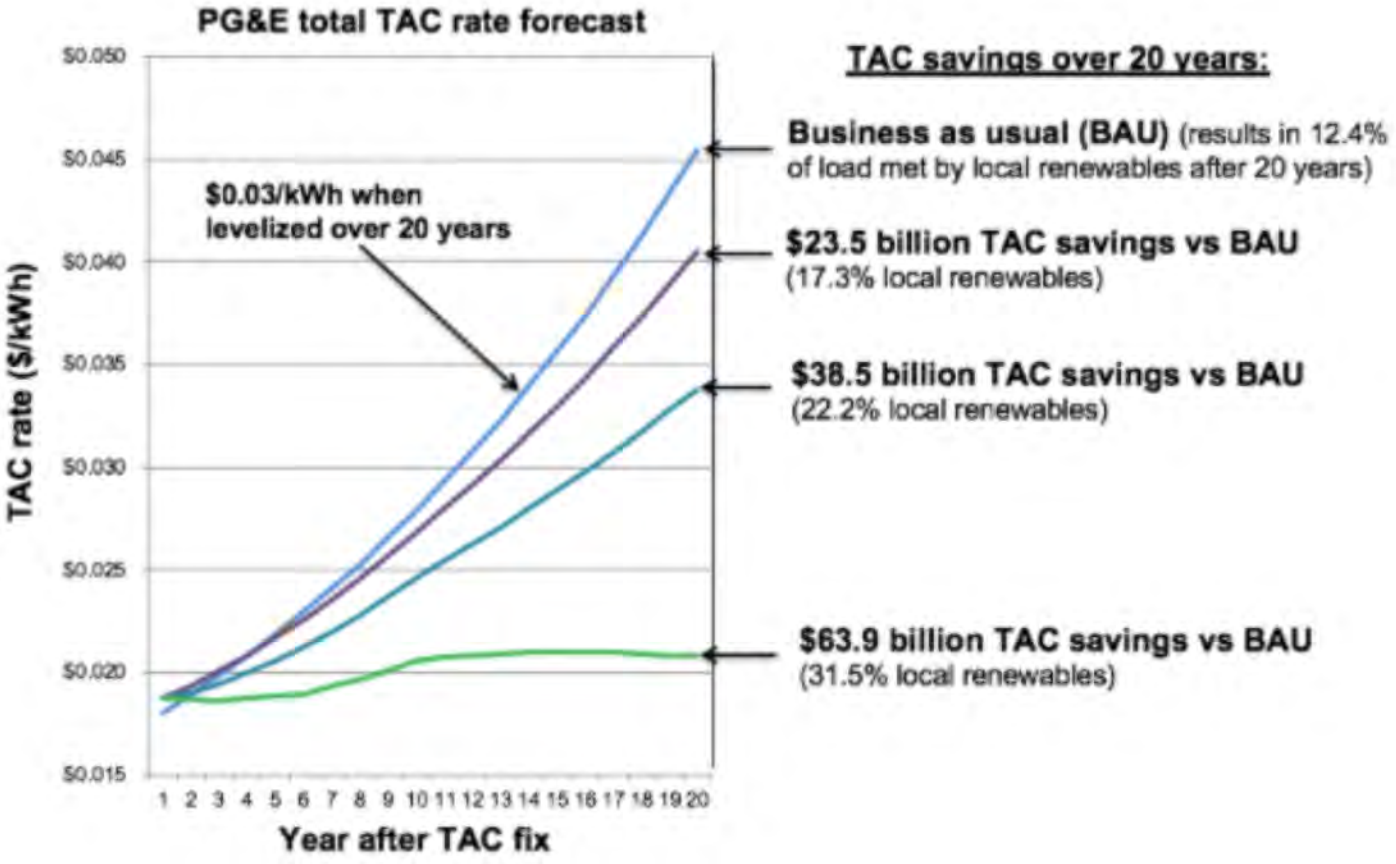
TAC are growing fast to ~4.5 cents/kWh over 20 years (levelized 3 cents/kWh)



The 20-year levelized TAC is about 3 cents/kWh, which is roughly 50% of the average wholesale cost of electricity in California!

Not fixing TAC could cost Californians $60 billion over the next two decades

- Generating energy closer to where we use it = less expensive transmission infrastructure, which lowers costs for ratepayers.
- Continuing with business as usual could cost Californians ~$60 billion in avoidable transmission costs over 20 years.



Proposed TAC reform and supporters

1. Only charge transmission fees for energy delivered through the transmission system.
2. Have procurement reflect both the energy purchase price and the delivery charges.

85+ organizations supporting, including CALSSA, Sunrun, Vote Solar, Sierra Club California, The Climate Center, 350 Bay Area, 350 San Diego, Enphase, Microgrid Resources Coalition, California Alliance for Community Energy, California Consumers Alliance, Californians for Energy Choice, Center for Biological Diversity, Center for Sustainable Energy, Climate Action Campaign, East Bay Power Alliance, Environment California Local, Fossil Free California, San Diego Energy District — and many more.

- For more, see: https://clean-coalition.org/policy/transmission-access-charges
- Sign on your organization to support the TAC Campaign: https://forms.gle/x6vdjz8Qg5YUqckKA

Backup slides

Evidence that local renewables defer transmission spending

- Preempting transmission spending by deploying local renewables is not theoretical.
- In CAISO's 2017–2018 planning process, they **deferred $2.6 billion in planned transmission spending.**
- This was due in large part to increased deployment of local renewables + increased energy efficiency (see https://www.utilitydive.com/news/efficiency-ders-saving-26b-in-avoided-transmission-costs-caiso-says/519935/)
- In 2021, utilities are charging ratepayers $4 billion in transmission.
- This is a 66% increase over 2016 in PG&E territory alone.
- Utilities are also charging California ratepayers $5 billion in wildfire liability expenses.
- **These are the real cost shifts**.

Local clean energy or remote – who wins the battle?

June 23, 2021

Bill Powers, P.E., Powers Engineering

Overview 101 – major players

Investor-owned utilities (IOU), cost-of-service business model

- Earns revenue, guaranteed rate-of-return, building infrastructure (transmission & distribution lines, power plants).
- Historical driver was load growth, now renewables & reliability transmission projects, wildfire mitigation.

California Independent System Operator (CAISO):

- Market-based grid operator since 1998 - major proponent of new transmission, and new generation in urban load pockets.

California Public Utilities Commission (CPUC):

- Charged with keeping IOU rates "just and reasonable," tends to defer to CAISO regarding technical support for new projects.

Traditional model does not accommodate distributed generation (DG) at customer site

- **Edison Electric Institute (EEI), IOU trade association**

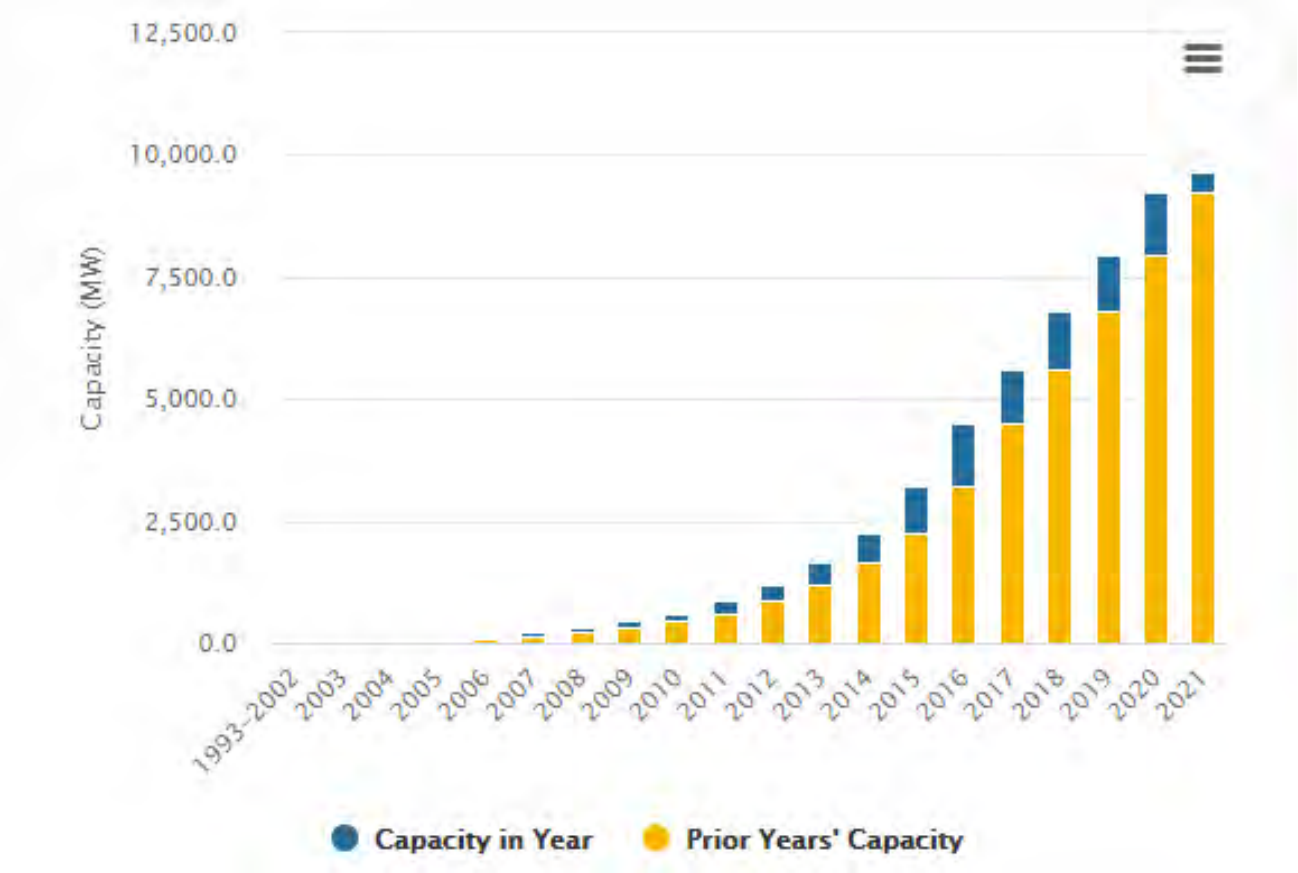
  EEI on DG, 2012:[1] "prospect of declining retail sales and earnings; financing of major investments in the T&D [transmission and distribution] . . . ; potential obsolescence of existing business and regulatory models."

- EEI is architect of the NEM solar cost shift attack strategy.
- CA's IOUs onboard - each give about $2 million/yr to EEI.[2]

1) Environment America, *Blocking the Sun - 12 Utilities and Fossil Fuel Interests That Are Undermining American Solar Power*, October 2015, p. 4.
2) Most recent IOU GO-77 executive compensation and contribution reports on dedicated CPUC webpage, accessed June 13, 2021: https://www.cpuc.ca.gov/General.aspx?id=6442454119. SDG&E 2019 GO-77, p. 38 and p. 56, SDG&E paid EEI $1.843 million in dues and contributions in 2019; PG&E 2018 GO-77, p. 118, PG&E paid EEI $2.263 million in dues and contributions in 2018; SCE 2018 GO-77, p. 92, SCE paid EEI $1.871 million in dues and contributions in 2018.

DG solar is very popular in California, 10,640 MW and counting

source: California Distributed Generation Statistics (IOU only as of 4/30/21), June 22, 2021: https://www.californiadgstats.ca.gov/charts/



DG battery storage is popular too

source: Center for Sustainable Energy, Self-Generation Incentive Program, last updated June 8, 2021 (battery storage only): https://sites.energycenter.org/sgip/statistics

DG solar also integral part of CPUC's Energy Efficiency Strategic Plan

source: CPUC webpage, *Energy Efficiency Strategic Plan – January 2011*, accessed 22, 2021: https://www.cpuc.ca.gov/General.aspx?id=4125 .

EE Strategic Plan Goals:

- Rooftop solar on all new residential construction, beginning in 2020.
- Twenty-five (25) percent of existing residential achieves near zero net energy by 2020.
- Fifty percent (50) of commercial reaches zero net energy by 2030.

AB 327 (2013):

- CPUC ensure that "*customer-sited renewable distributed generation continues to grow sustainably*"

Types of DG solar, available capacity

Types:

- NEM solar – behind the meter
- Wholesale DG – in front of the meter
- IOU-owned wholesale DG (SCE warehouse project)

Available capacity, City of San Diego example:[1]

- >10,000 GWh per year of available local solar potential on rooftops and parking lots.
- More than double the 4,000 GWh needed to achieve a 100 percent local clean energy build-out by 2030.

1) B. Powers, *Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego*, May 2020, p. 24: https://protectourcommunities.org/wp-content/uploads/2020/06/2020-06-06-Roadmap-V1.1.pdf.

2020 pricing of DG solar and utility-scale solar and wind

NREL Q1 2020 DG solar:[1]

- Commercial: $0.049/kWh
- Residential: $0.071/kWh

2021 Padilla report, utility-scale solar and wind:[2]

- Utility-scale solar: $0.027/kWh
- Utility-scale wind: $0.045/kWh

1) NREL, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020, January 2021*, p. 102, Appendix B, Table B-1: https://www.nrel.gov/docs/fy21osti/77324.pdf [residential and commercial rooftop prices shown represents a high solar resource site, with the federal Investment Tax Credit (ITC)].

2) CPUC, *2021 Padilla Report – Costs and Cost Savings for the RPS Program*, May 2021, Table C-2, p. 29: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2021/2021%20Padilla%20Report_Final.pdf.

Impact of cost of new transmission on all-in cost of remote wind and solar

Case studies:

- SDG&E 500 kV Sunrise Powerlink: $1.883 billion
- SCE Tehachapi Renewable Transmission Project: $3.062 billion
- SCE El Dorado-Ivanpah Transmission Project: $350 million

SDG&E 500 kV Sunrise Powerlink (SPL)

- Final capital cost: $1.883 billion
- Final annualized cost: $254 million/yr
- Rejected in October 2008 proposed decision as unnecessary for near-term reliability & no RPS deficit to meet
- Approved December 2008, voluntary SDG&E commitment to add 1,000 MW of solar
- Current interconnected renewables : 999 MW solar,
  265 MW wind
- Total renewables annual production: 2,873,543 MWh/yr
- Cost premium of SPL transmission line: $0.09/kWh

Tehachapi Renewable Transmission Project

Tehachapi Renewable Transmission Project

- Final capital cost: $3.062 billion
- Final annualized cost:[1] $407 million/yr
- Projected capacity: 4,500 MW
- Actual capacity:[2] 4,019 MW
- Total renewables annual production: 9,141,279 MWh/yr
- Cost premium of TRTP transmission line: $0.045/kWh

1) Extrapolated from Sunrise Power capital cost to annualized cost ratio.

2) 1,524 MW solar (Kern and LA Counties) and 2,495 MW wind (Kern County), CAISO Generator Interconnection Queue, accessed June 11, 2021: http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx.

SCE 500 MW warehouse rooftop project, 2009

CPUC press release on approval of 500 MW SCE warehouse rooftop solar (June 2009):

> *Unlike other generation resources, these (large-scale rooftop solar) projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts.*

1) CPUC press release, *CPUC Approves Edison Solar Roof Program*, June 18, 2009: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/NEWS_RELEASE/102580.PDF.

CPUC's 2009 Re-DEC Forum – DG is the future

source: E3 and B&V, *Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis*, Re-DEC Working Group Meeting, December 9, 2009

33% RPS Reference Case	High DG Case
	

CPUC's 2009 Re-DEC Forum (continued)

source: E3 and B&V, *Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis*, Re-DEC Working Group Meeting, December 9, 2009, p. 11.

"*If it is conservatively assumed that only 10,000 MW of new high voltage transmission will be built by 2020 . . . the estimated cost of this transmission will be in the range of $20 billion in 2008 . . . How much thin-film PV located at IOU substations or at the point-of-use on commercial buildings or parking lots could the IOUs purchase for this same $20 billion? ... This equals an installed thin-film PV capacity of 14,000 to 18,000 MW for a $20 billion investment*."

- Bill Powers, PE, testimony in SDG&E's Sunrise Powerlink CPCN case.

El Dorado-Ivanpah Transmission Project, 2010

source: https://www.sce.com/about-us/reliability/upgrading-transmission/eldorado

E3 under contract to Brightsource (Ivanpah) and First Solar (Desert Stateline), rebuts viability of DG as alternative:[1] "*If the Commission finds that EITP is not needed because DPV (distributed solar) is a superior alternative, then the Commission will be unable to approve the applications of any new renewable transmission projects . . .*"

1) A.09-05-027, Application of SCE for a Certificate of Public Convenience and Necessity for the Eldorado-Ivanpah Transmission Project – Rebuttal Testimony of Arne Olson on Behalf of Brightsource Energy, Inc. and First Solar, Inc., July 30, 2010.

NEM solar cost-shift controversy

- **Next 10/Haas, February 2021:** fixed cost gap not being paid by NEM solar customers is $700 - $900/year, depending on the IOU.
- **Primary omission in balance sheet is failure to account for the true avoided transmission value of NEM solar:**
  - To eliminate new transmission otherwise justifiable on peak load growth, congestion, reliability need.
  - To avoid new transmission justified to make deliverable remote utility-scale solar and wind to meet GHG reduction targets.
  - To avoid very high T&D grid hardening costs for wildfire mitigation.
- Fair accounting of these NEM solar benefits fully offsets the asserted cost shift.

1) Next 10 & Haas, *Designing Electricity Rates for An Equitable Energy Transition*, February 2021, p. 40.

Avoided transmission cost value of NEM solar

Avoided PG&E reliability transmission projects, 2018:

- $2.6 billion in cancelled PG&E projects, CAISO attributes to energy efficiency and unexpected growth of NEM solar.
- $1.3 billion attributable to NEM solar (Powers Egr estimate), $175 million/yr annualized value.
- 1,685 MW of NEM solar added in 2015-2017 period of interest.
- $620/yr/system avoided cost (assumes 6 kW_{AC} systems).

Avoided RPS transmission cost:

- SPL example, $254 million/yr, 1,264 MW solar & wind interconnected.
- Equivalent renewables production with 240,000 6 kW_{AC} systems.
- $1,050/yr/system avoided RPS transmission cost.

Avoided transmission cost value of NEM solar, TRTP example

Avoided TRTP transmission cost:

- SPL example, $407 million/yr, 4,019 MW solar & wind interconnected.
- Equivalent renewables production with 850,000 6 kW_{AC} systems.
- ~$500/yr/system avoided TRTP RPS transmission cost.

Combined avoided transmission peak load and GHG reduction cost benefits of NEM solar – at least $1,000/yr/system

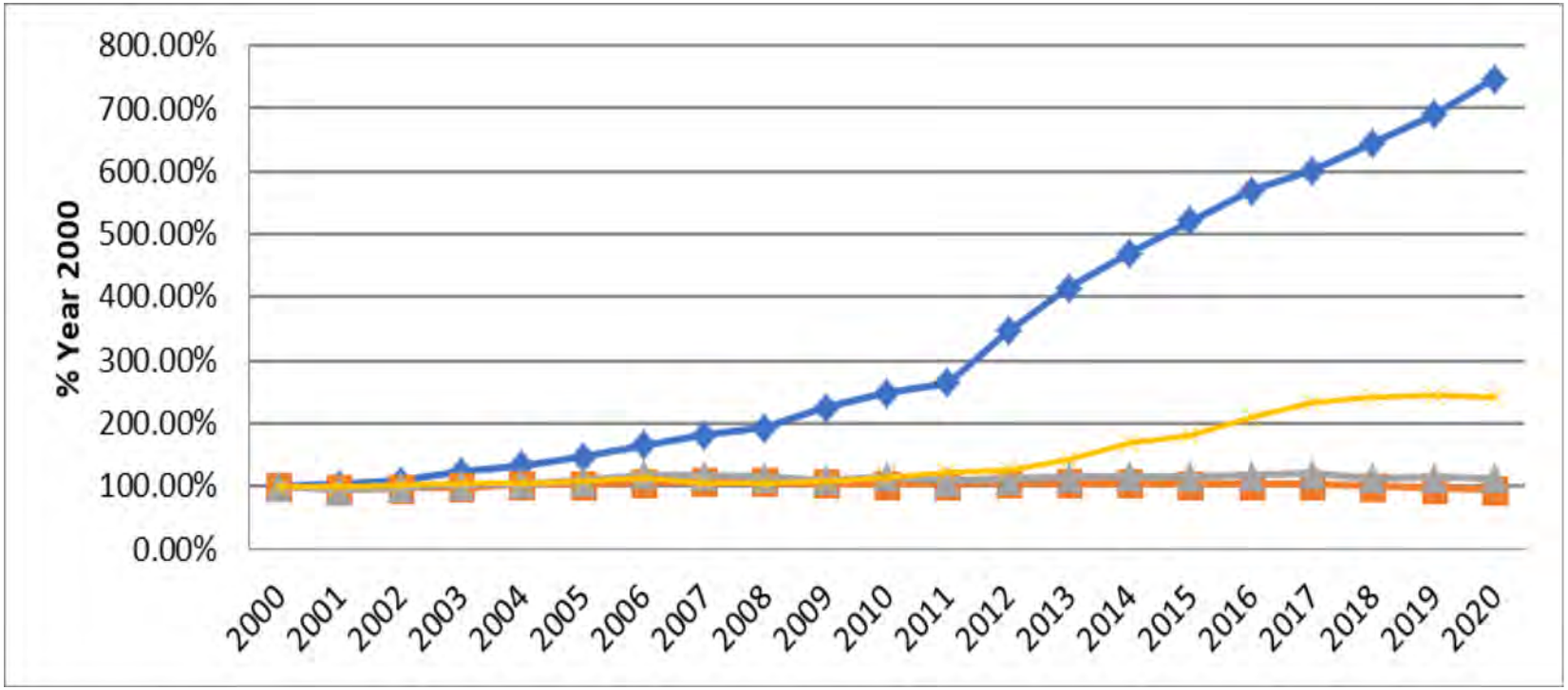
Source of legacy fixed costs

- **Generation fixed costs:** CPUC 2018 decision on exit fees very favorable to the IOUs. Fixed exit fees on departing load (CCA) customers approaching $0.05/kWh.[1] Should be $0.005/kWh and falling.[2]
- **Transmission fixed costs:** CAISO driving relentless rise in transmission capital expense over last 20 years.
- **Distribution fixed costs:** Rapidly rising grid hardening wildfire mitigation-related investments.

1) SDG&E, SDG&E – SEA Joint Rate Comparisons, Standard – DR-Residential "SEA Choice" rate, as of March 1, 2021: https://www.sdge.com/sites/default/files/JRC%20Online%20Tempate%2003.01.2021%20SEA_1.pdf.
2) Protect Our Communities Foundation, *Opening Brief – A.17-06-026 Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment*, June 1, 2018, Attachment A.

Transmission fixed costs – spectacular rise since CAISO became grid operator

source: J. Firooz, P.E., June 21, 2021: http://protectourcommunities.org/wp-content/uploads/2021/06/2021-06-21_data-revisions_J-Firooz_Is-the-CAISO-bringing-benefits-to-california-consumers-2019-update.pdf. Blue = growth in CA IOU transmission plant value; yellow = growth in renewable energy production; gray = growth in non-coincident peak load; orange = growth in annual demand.



CAISO – Never enough supply, and declining grid reliability

- California needs to rethink the utility of CAISO as grid operator.
- Huge increase in costs under CAISO's watch, yet less grid reliability.
- Opaque and counterintuitive operations – allowing 1,000 MWs of exports under tight demand conditions (Aug. 14-15, 2020).
- Diffuse responsibility – no one is responsible for blackouts.
- Flex alerts under moderately high summer demand conditions – creates unwarranted sense of grid fragility in the public mind.[1]

1) CAISO, Flex Alerts called for Thursday and Friday, June 17 and 18 (2021): http://www.caiso.com/about/Pages/Blog/Posts/Flex-Alert-In-Effect-from-5-p-m-to-10-p-m-Thursday-June-17.aspx.

The status quo future – without DG solar, relentlessly rising T&D

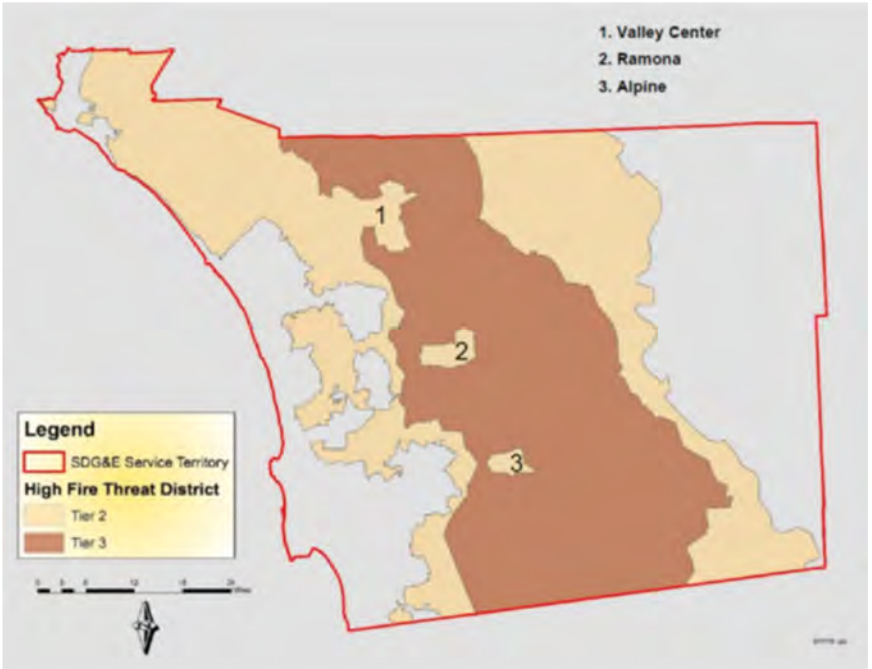
- Wildfire mitigation grid hardening, projected ~$40 billion spending primarily on pole conversions and undergrounding, 2021-2030.[1]
- Power shutoffs to continue.
- SDG&E seen as leader – yet no vetting by CPUC of need or cost of grid hardening actions.[2]
- No role planned for DG solar + battery storage as low-cost solution.

1) CPUC, *Utility Costs and Affordability of the Grid of the Future*, February 2021, p. 60. Total forecast California IOU spending on wildfire mitigation, 2021-2030 = $38.9 billion.
2) CPUC, D.16-05-038, p. 12.

Few customers in extreme High Fire Threat Districts - ideal for DG solar + batteries as low cost solution

SDG&E example:

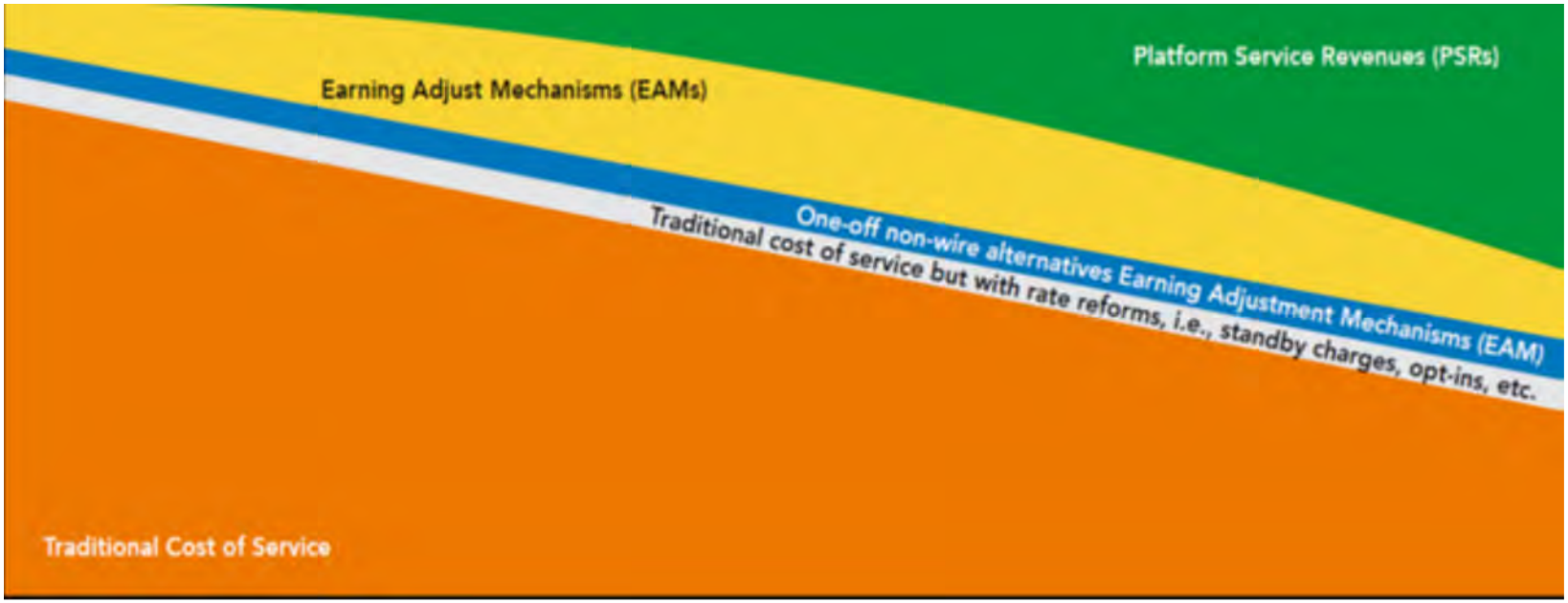
- 31,181 customers in Tier 3 HTFDs, out of 1.5 million total customers.
- Average of 20 customers per mile of distribution line.
- $3.1 million per mile to underground, $150,000/customer.
- 1,658 miles of distribution lines in Tier 3 HFTDs.
- ~$5 billion to underground all distribution lines in Tier 3.
- ~$16,000/yr/system avoided cost.



1) CPUC R.18-10-007, *Protect Our Communities Foundation Comments on 2020 Wildfire Mitigation Plans Pursuant to Resolution WSD-001*, April 7, 2020, p.p. 30-31.

Time to address mismatch between traditional revenue methods and modern electric system needs

source:NREL, *Next-Generation Performance-Based Regulation, Volume 1: Introduction— Global Lessons for Success*, April 2018, p. 3: https://www.nrel.gov/docs/fy18osti/70822.pdf.



Conclusion – California needs to fundamentally reassess its approach

- The traditional IOU cost-of-service regulatory model is hobbling California's ability to achieve a cost-efficient DG future.
- CAISO is not adding value, only much higher fixed costs and poorer reliability. The state needs to plan for a future without CAISO.
- DG solar is dampening transmission costs that would be substantially higher without it. It is not being credited for these savings in regulatory models. There is no cost shift.
- DG solar + storage is the low-cost solution to wildfire mitigation. It should be used for this purpose and credited w/billions saved.

Clean Coalition Webinar
Rao Konidena

June 23

Agenda & Key Takeaways

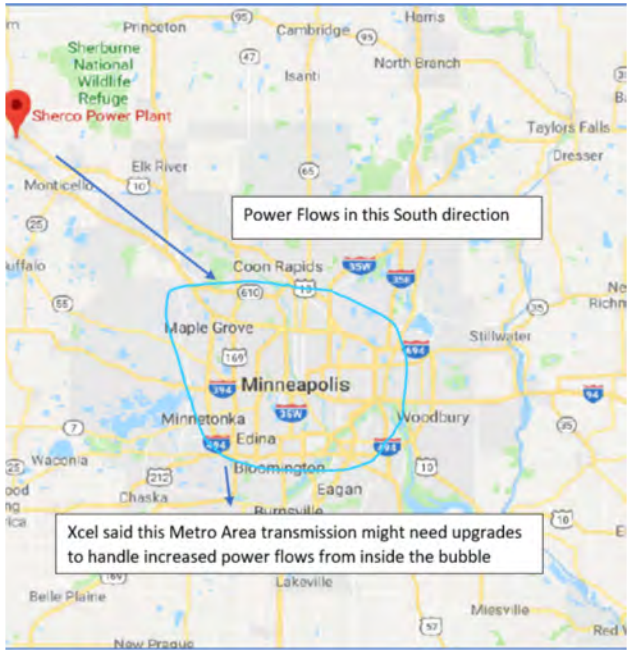
- MISO MVP Line Case Study
- Midwest i.e., Xcel Energy in Minnesota - Case Study

MISO MVP Line Case Study Highlights

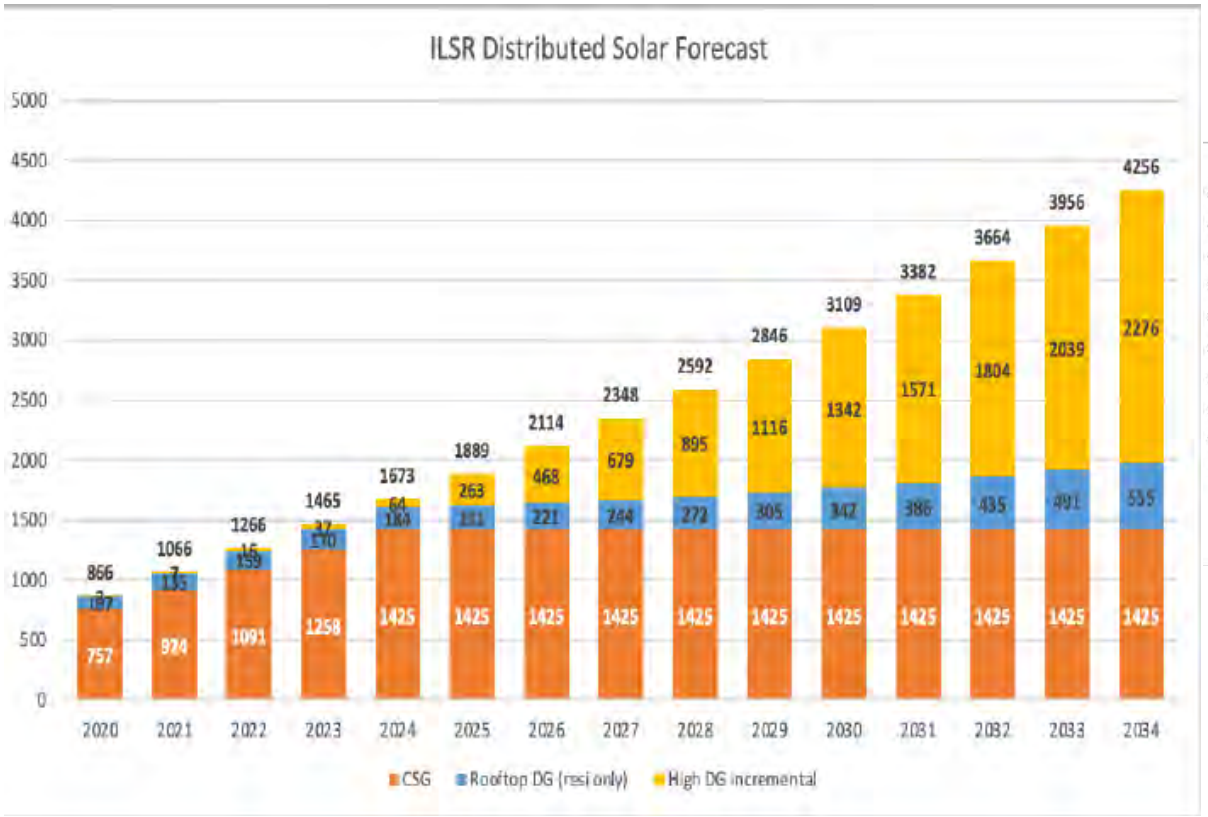
Applicants said	Expert showed
There is a reliability threat in Wisconsin if the line is not approved in time	there is no reliability threat in 2019 in Wisconsin. MISO had processes and procedures to handle any near-term reliability need arising from delaying the CHC line in Wisconsin.
the line reduces the operating reserves at MISO	showed from MISO studies that operating reserves were reduced already due to ancillary service market requirements
Day ahead market binding constraints report showed the need for the T line	specific binding constraints focused by the applicants were not binding in real-time
Delaying T line would have “ripple effects”	that MISO-approved transmission projects were delayed in the past, some as long as 8 years, and 26 projects in one study cycle
CHC line is needed for generation retirements	that generation retirements have been happening for over a decade in Wisconsin to meet WI utility goals
When MISO said, resource adequacy is of concern in Wisconsin, citing a report with the Organization of MISO States (OMS),	Michigan had the same problem, but it was OK.
without CHC line, there would be voltage collapse in Wisconsin	focused on voltage support and reactive support requirements of new renewable interconnections mandated by FERC

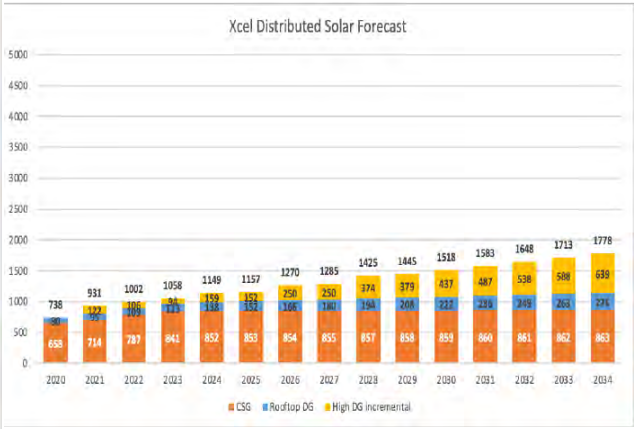
Midwest case study: Benefits of high-penetration distributed solar relative to Xcel Energy generation

- NSP must improve its planning to include additional distributed resources and treat them as a “central element to the utility’s optimized plan.”
- Distributed resources interconnected to Xcel’s distribution system avoid the MISO queue process that is currently backed up by more than a few years and which neither the Commission nor Xcel can control.
- MISO is currently modeling more than 3,000 MW of DG PV in 2021 transmission planning models. Those model runs demonstrate that a much higher level of distributed solar can be economically added to the system than Xcel is currently planning.
- Distributed solar, especially distribution connected DG within the Twin Cities Metro Area should have a higher Effective Load Carrying Capability (ELCC) than utility scale solar connected at transmission to remote nodes.
- Distribution connected solar avoids distribution and transmission system costs in addition to providing resource benefits. Aligning distribution, transmission, and resource planning will reveal currently unrealized value.



Xcel must improve its DG modeling





Distributed resource interconnections are under the purview of Relevant Electric Retail Regulatory Authorities (RERRAs)

- Distributed Generation Avoids Transmission Interconnection Limitations
  - MISO Deliverability Study ensures High Distributed Solar (HDS) is available for the entire MISO load
  - HDS capacity obligation reduction benefit
  - HDS as a resource in Fixed Resource Adequacy Plan (FRAP) must offer into MISO energy market

Table I-1: Capacity Obligation Calculation - 2020 Example		
Total Capacity Obligation Component	Value	Units
Forecasted Load	9,115	MW
NSP Effective Reserve Margin	1.0346	Number
NSP Obligation	9,430	MW

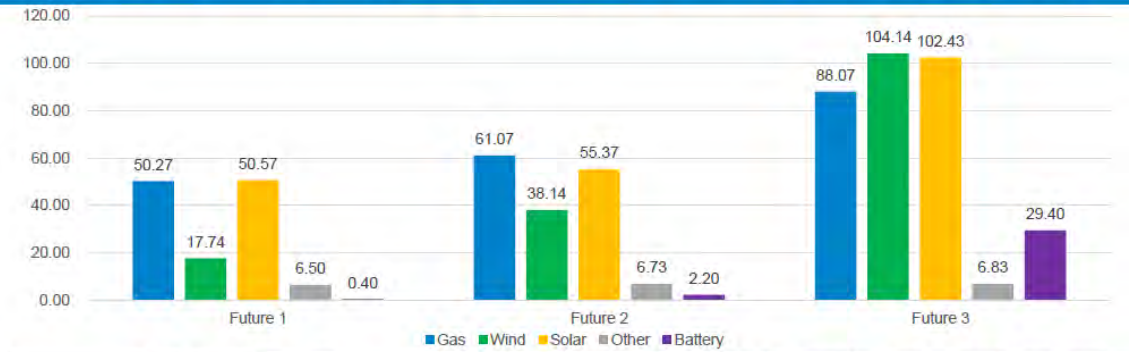
Table I-1: Capacity Obligation Calculation - 2020 Example Recreated with 1,000 MW of reduced peak load		
Total Capacity Obligation Component	Value	Units
Forecasted Load	**8,115**	MW
NSP Effective Reserve Margin	1.0346	Number
NSP Obligation	**8,396**	MW

MISO modeling already shows DG PV as economic at the regional level

Future I	Future II	Future III
• The footprint develops in line with 100% of utility IRPs and 85% of utility announcements, state mandates, goals, or preferences. • Emissions decline as an outcome of utility plans. • Load growth consistent with current trends.	• Companies/states meet their goals, mandates and announcements. • Changing federal and state policies support footprint-wide carbon emissions reduction of 60% by 2040. • Energy increases 30% footprint-wide by 2040 driven by electrification	• Changing federal and state policies support footprint-wide carbon emissions reduction of 80% by 2040. • Increased electrification drives a footprint-wide 50% increase in energy by 2040.

- MISO models show 6 GW of DG PV
- But there is lot more DG PV potential
- Xcel did not "offer" DG PV as a resource like MISO does

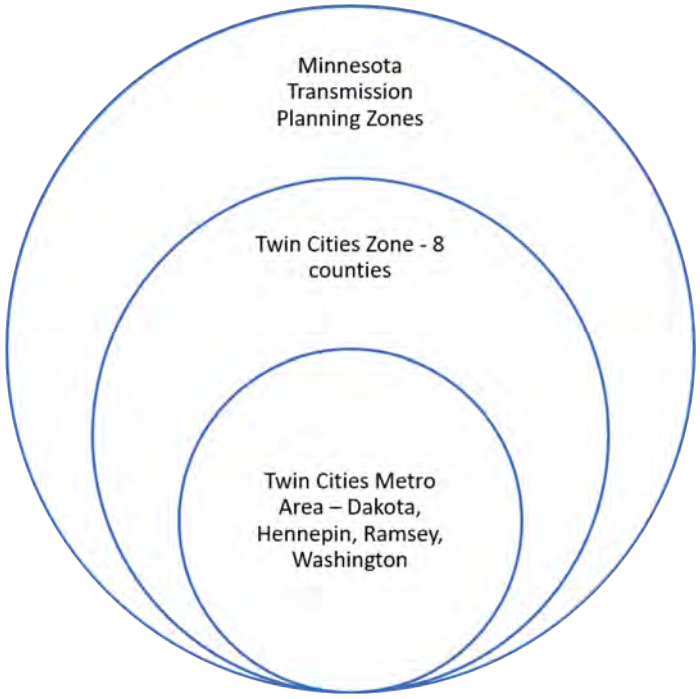
Resource Additions by Future through 2039 (GW)



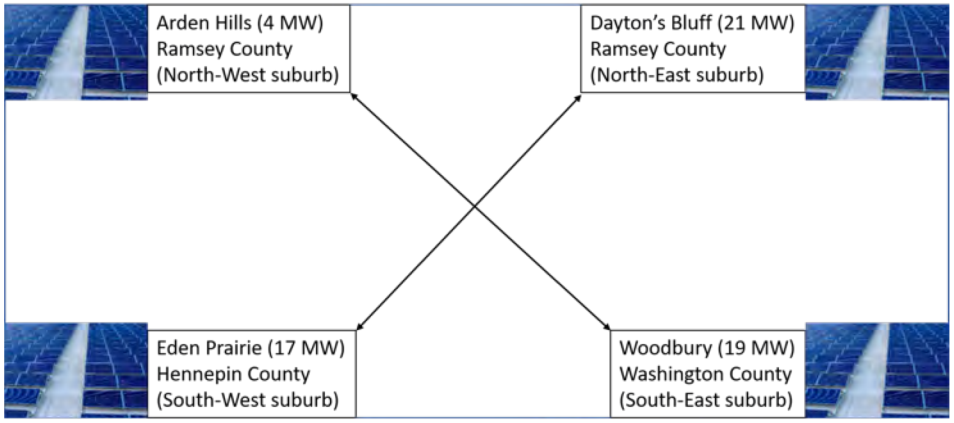
Total Resource Additions (GW)			
Resource	Future 1	Future 2	Future 3
Natural Gas (CT, CC, CC+CCS)	50.27	61.07	88.07
Wind	17.74	38.14	104.14
Solar (Solar, DG PV, & Solar+Battery Hybrid)	50.57	55.37	102.43
Battery	0.40	2.20	29.40
Other (Hydro & Energy Efficiency)	6.50	6.73	6.83

	Total Additions (GW)			Queue/IRP Additions (GW)			EGEAS Additions (GW)		
	Future 1	Future 2	Future 3	Future 1	Future 2	Future 3	Future 1	Future 2	Future 3
CC	36.18	52.98	48.18	12.18	12.18	12.18	24.00	40.80	36.00
CT	14.09	5.09	5.89	5.89	5.89	5.89	7.20	1.20	0.00
CC+CCS	0.00	0.00	33.00	0.00	0.00	0.00	0.00	0.00	33.00
Wind	17.74	38.14	104.14	17.74	17.74	17.74	0.00	20.40	86.40
Solar	35.14	38.74	31.54	17.14	17.14	17.14	18.00	21.60	14.40
Hybrid	12.01	13.21	64.81	0.01	0.01	0.01	12.00	13.20	64.80
Battery	0.40	2.20	29.40	0.40	0.40	0.40	0.00	1.80	29.00
DG PV	3.42	3.42	6.08	1.28	1.28	1.28	2.14	2.14	4.80
Hydro	0.08	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00
EE	6.42	6.65	6.75	0.00	0.00	0.00	6.42	6.65	6.75

ELCC for distributed generation is better than utility scale generation



Simple Concept – If we locate DG closer to load, the ELCC would be higher than utility scale solar. As a result, a higher capacity contribution to resource adequacy requirement.



Source for solar picture - Photo by Angie Warren on Unsplash

Distributed generation located near load avoids Transmission and potentially Distribution upgrades

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2017-TC-N1	Airport-Rogers Lake 115 kV Rebuild	2016/B>A	10074	No	No	XEL
2017-TC-N4	Black Dog-Wilson 115 kV Uprate	2017/C>A	11993	No	No	XEL
2017-TC-N5	Wilson Substation	2017/C>A	4695	No	No	XEL
2017-TC-N6	Plymouth-Area Power Upgrade	2018/C>A	14054	No	Yes	XEL
2017-TC-N7	Lebanon Hills 115 kV	2018/A	12211	No	No	GRE
2019-TC-N1	Red Rock Transformer Uprate	2018/A	14844	No	No	XEL
2019-TC-N2	South Afton Substation	2019/A	15730	No	No	XEL
2019-TC-N3	East Metro Area Upgrades	2019/A	15877	No	No	XEL

The above table provides a list of transmission needs identified in the Twin Cities Zone by MISO utilities. There were no projects identified in this zone by non-MISO utilities.