| DOCKETED | |
|---|---|
| **Docket Number:** | 16-OIR-06 |
| **Project Title:** | Senate Bill 350 Disadvantaged Community Advisory Group |
| **TN #:** | 259548 |
| **Document Title:** | Item 6 - Electric Rates 101_DACAG_Oct 18 2024 |
| **Description:** | N/A |
| **Filer:** | Dorothy Murimi |
| **Organization:** | California Energy Commission |
| **Submitter Role:** | Commission Staff |
| **Submission Date:** | 10/16/2024 10:29:26 AM |
| **Docketed Date:** | 10/16/2024 |

# CALIFORNIA ELECTRIC RATES 101

BRIEFING ON COST RECOVERY METHODS AND PRICING STRATEGIES FOR THE GRID OF THE FUTURE

CPUC Energy Division

October 18, 2024

# OVERVIEW

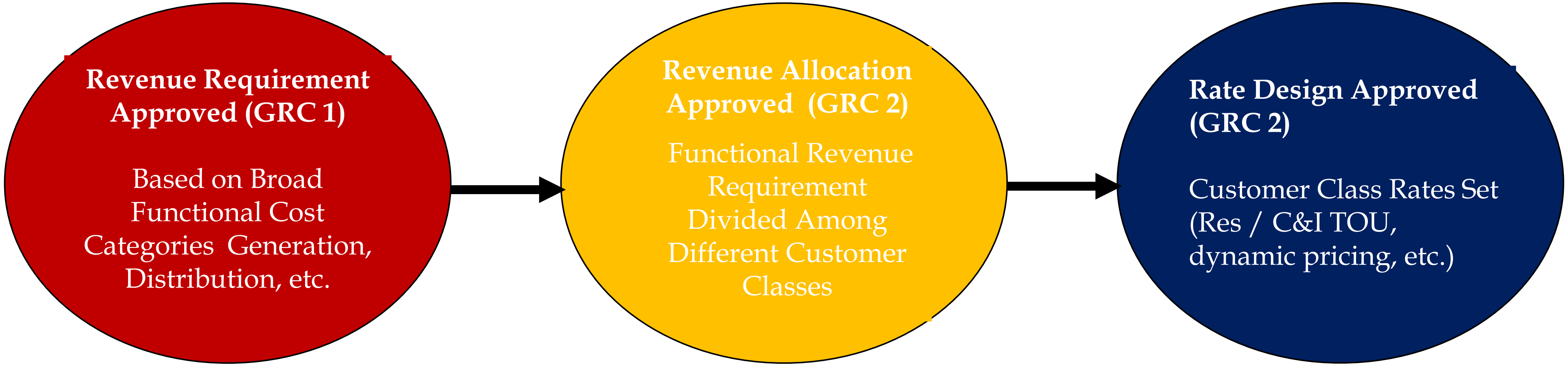
1. Fundamentals of Residential and Commercial Electric Rate Design (20 mins)
2. The Income Graduated Fixed Charge and Ratepayer Benefits (15 mins)
3. Advanced Pricing Strategies, Electrification and Cost Containment (15 mins)
4. Q&A Session (10 mins)

# The Fundamentals of Residential and Commercial Electric Rate Design

Presenters: Paul Phillips & Achintya Madduri

# Electric Utility Rates Are Adjudicated in Major Formal Proceedings

The CPUC sets rates and applies adjustments to ensure that utilities collect no more and no less than necessary to recover just and reasonable costs and to allow the utility to earn a fair rate of return.




- **General Rate Case (GRC) Phase 1 proceedings**: Determines operating revenues to recover operating costs and rate of return.
- **Energy Resource Recovery Account (ERRA) Forecast:** Determines operating revenues to recover fuel procurement costs, which are pass-through expenses---no rate of return on these costs.
- **Costs pursuant to legislative mandate:** Public Purpose Programs.
- **Regulatory Accounts Recovery:** CEMA, WMPMA, WMCE, etc.
- **GRC Phase II proceedings:** Evaluates marginal cost of service (the cost of providing an additional unit of electricity to meet customer demand) and allocates revenues based on cost causation by customer type and tariff.
- **Other Ratesetting proceedings:** For example, Rate Design Windows or Rulemakings that are categorized as ratesetting proceedings, such as the "NEM 3" proceeding.

# General Rate Case (GRC) Phase 1 - *Revenue Requirement*

**Determine Costs**

(Revenue Requirement)

- **Establishes Revenue Requirement for IOU (typically for the next 4 years).**
  - Revenue requirement is the total amount of money the utility is allowed to collect to cover all costs.
- **Focuses on fixed or highly predictable operating costs**
  - **Expenses**: Salaries, buildings, vehicles
  - **Capital investments** and **Return on Equity**
- **GRCs approve revenue requirement in broad categories and generally not for specific projects.**
- **GRCs are sometimes settled (partially or in full) as an overall agreement between advocacy groups and the IOU.**
  - CPUC rules require CPUC to still determine the settlement agreement is *"reasonable in light of the whole record, consistent with the law, and in the public interest…"*

# Energy Resource Recovery Account (ERRA) – *Revenue Requirement*

**Determine Costs**

(Revenue Requirement)

- **Procurement related costs, including:**
  - Power Purchase Agreements
  - CAISO market electric costs
  - Payments to Qualifying Facilities (QFs)
  - Greenhouse Gas (GHG) emission credit costs
  - Natural gas costs for gas-fired electric generators

- ***ERRA costs are pass through expenses, which means the IOU receives <u>no mark up or profit on these costs.</u>***

# GRC Phase II – *Revenue Allocation & Rate Design*

**Divide Costs Among Different Customer Classes**

(Revenue Allocation)

Allocating total revenue requirement to individual customer classes (residential, commercial, agricultural, industrial)  based on the utility's cost to serve that class.

**Set Rates**

(Rate Design)

Designing rate schedules and further allocating revenues to individual customers within a customer class. Rate design is also used to promote conservation or other desired outcomes.

# The Basics of Utility Costs, Rates, and Bills

After an Electric IOU GRC Phase II or other rate-setting proceeding, the authorized revenue requirement and authorized forecasted sales are implemented in current rates.

**Cost of Service** + **Rate of Return (Profit)** = **Revenue Requirement**

**Revenue Requirement** ÷ **kWh (Total Electric Demand)** = **Rates**

× **kWh (Customer Electric Demand)**

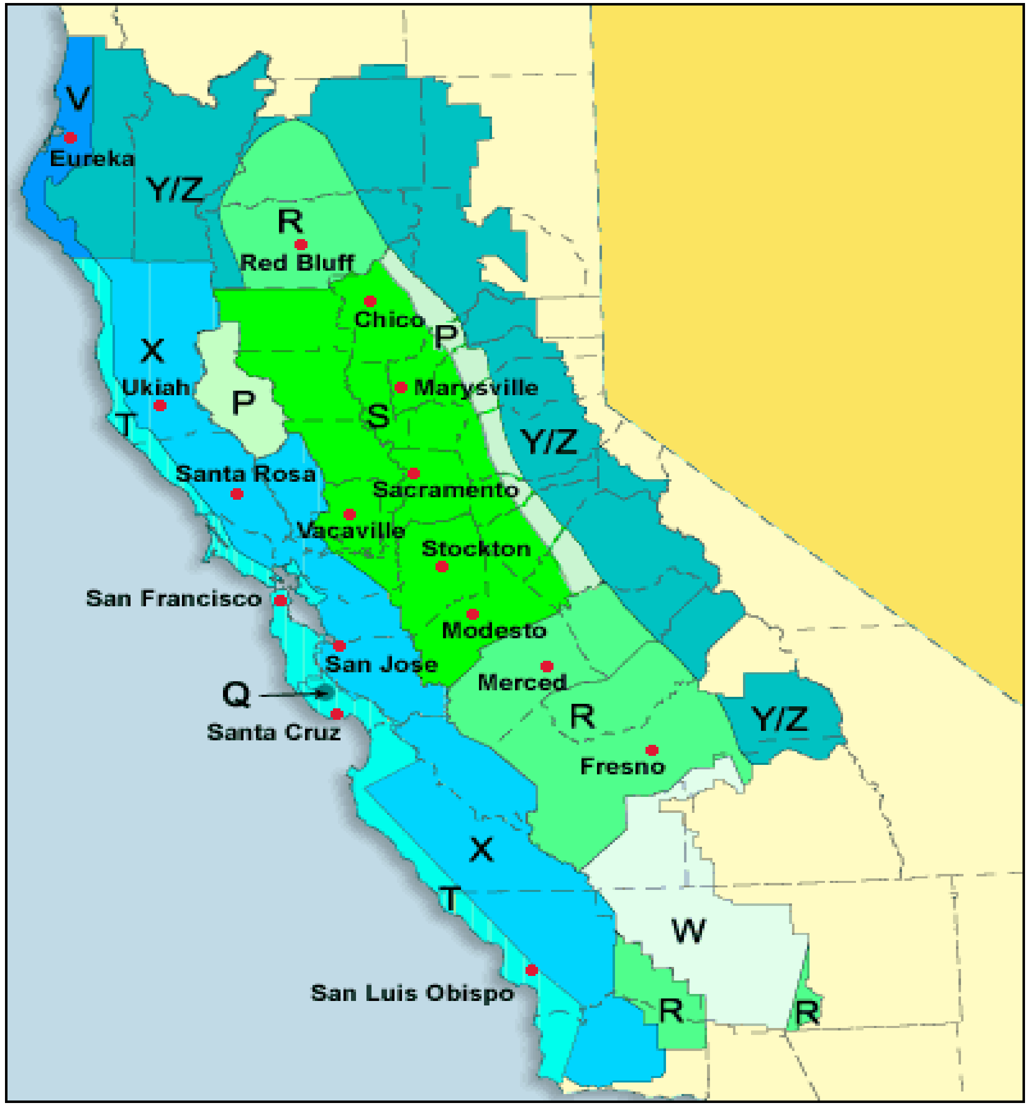
= **Bills**

**Customers Pay Bills, Not Rates**

- Historically, while California bundled residential average rates have been higher than most of the nation, bills have been lower due to usage in California being low compared to most of the United States.

- **However, low usage is no longer counteracting overall rate impacts, and bills are rising as a result of higher rates.**

# Tier 1 Electric Baseline Quantities – *PG&E Baseline Territories*



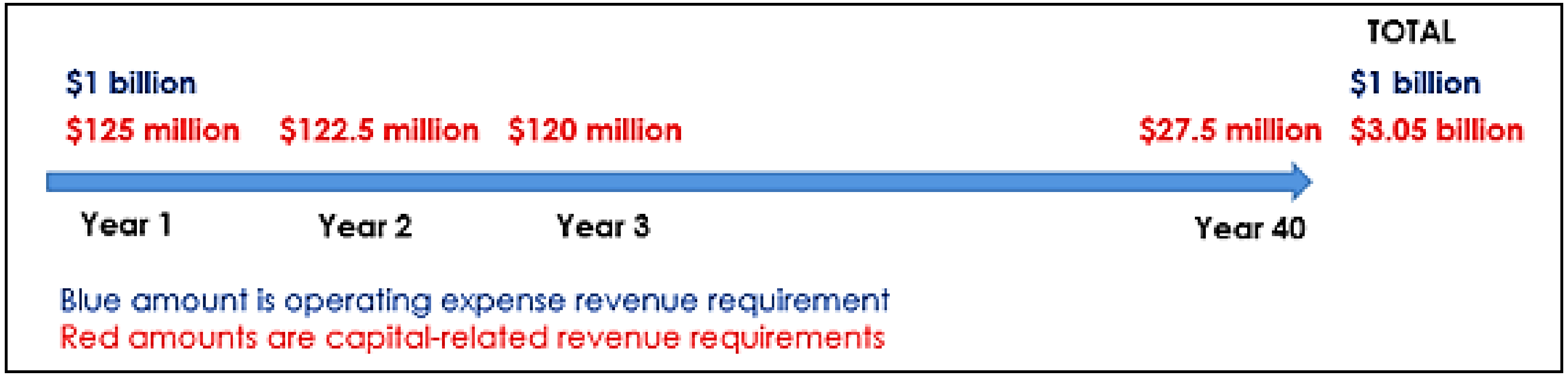

- Defined by statute as a quantity "necessary to supply a significant portion of the reasonable energy needs of the average residential customer."
  - Basic electric baseline quantity for residential customers, in kWh, is defined by statute as 50% to 60% of average residential consumption of electricity.
  - Hotter baseline territories are accorded a greater baseline quantity to reflect higher average usage, such as that arising from air conditioning use.
  - Baseline quantity usage is billed at the lower Tier 1 rate.
  - TOU rates can also have baseline quantities, resulting in a "baseline credit" for usage within the baseline quantity.

# Operating Expenses vs. Capital-Related Revenue Requirement

Operating expense and capital-related costs authorized for recovery during ratesetting proceedings **must be converted to revenue requirement** to be recovered in rates.

- Operating expenses convert to revenue requirement on a 1:1 basis with no authorized rate of return (profit).
- Only a fraction of capital-related costs convert to revenue requirement in any given year: (1) **depreciating expense** as the asset depreciates over time and (2) **authorized rate of return (profit)** on the net capital investment (rate base).

**Comparison of Timing of Recovery of $1 Billion in Costs**
**(Operating Expense Revenue Requirement versus Capital-Related Revenue Requirement)**




*A difference of about $2 billion due to the total return (profit) paid by ratepayers*

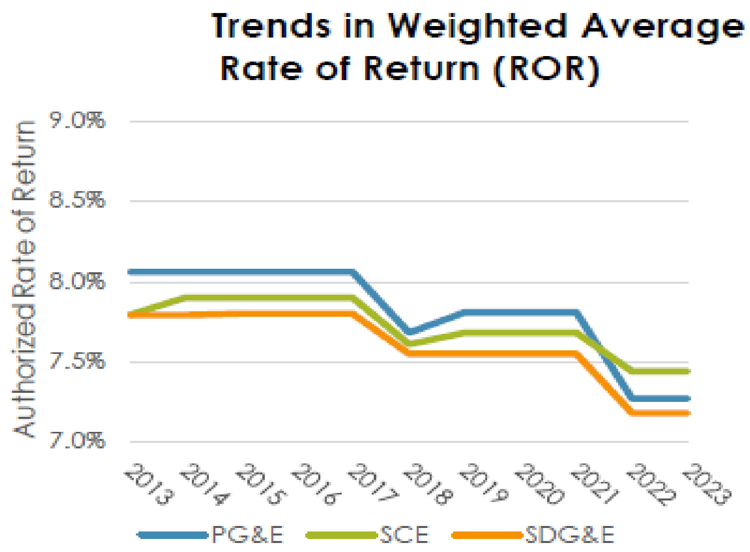
- As CapEx grows, the capital-related revenue requirements also grow as the function of two effects—**increased depreciation expense and increased return on the net capital investment.**

# Return on Rate Base Revenue Requirement

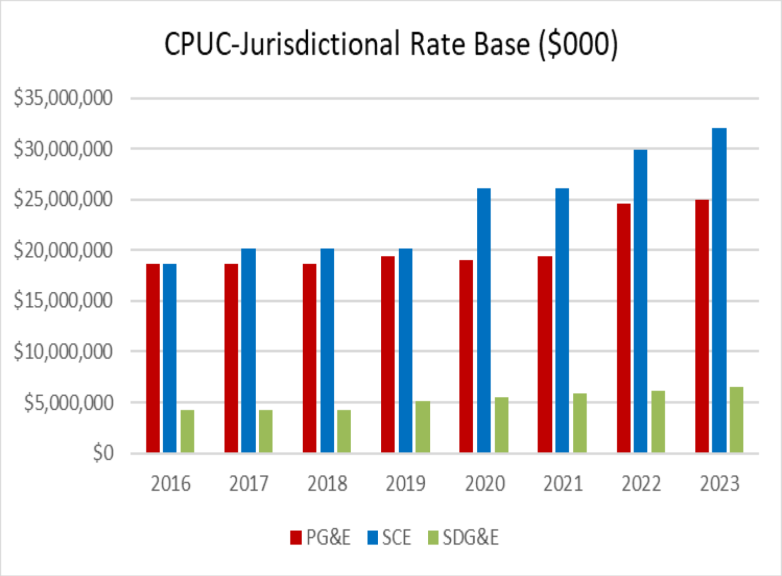
CPUC-authorized ROR, which is the weighted average cost of debt and equity used to finance capital investments, has declined over the last ten years:

However, CPUC-jurisdictional rate base, which is the utility's net capital investment, has been increasing:

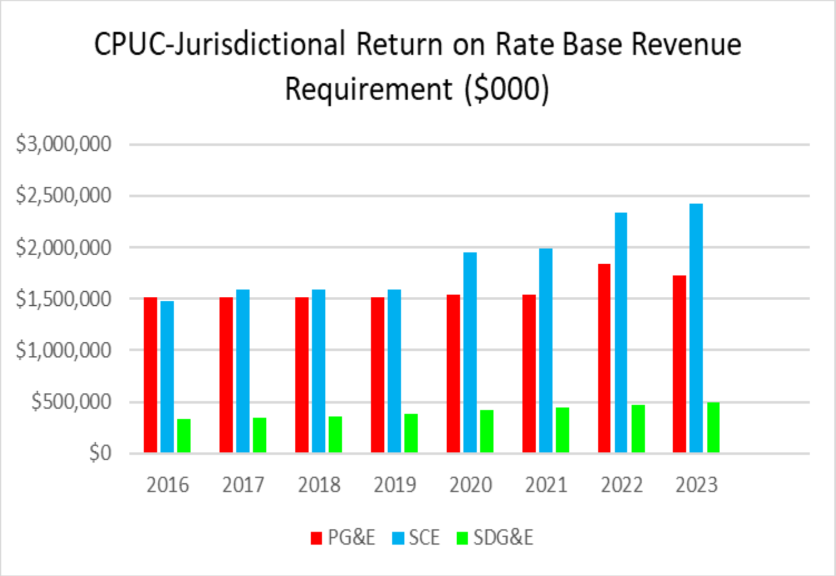
ROR is multiplied by rate base to calculate what is an increasing return on rate base revenue requirement, which ends up in customer bills:




*Source*: 2023 AB 67 Report




*Source*: 2024 SB 695 Report




*Source*: 2024 SB 695 Report

*It is estimated that in 2023, the return on rate base revenue requirements shown above comprised the following percentages of a typical residential customer's bill:* ***PG&E 10%, SCE 13%, SDG&E 10%.***

# The Importance of Rate Base & Return on Rate Base

- IOU **Rate Base** is the value of the company's undepreciated assets and provides a basis for computing rates of return, calculated as **capital additions (capex) net of accumulated depreciation**.

- **Return on Rate Base** (ROR), which primarily reflects the opportunity for the IOU to earn a profit, has **been increasing at an annual average rate of about 1.3% to 7.7% since 2016.** The growth in rate base started in 2019 with the implementation of wildfire mitigation programs.

- The ROR figures below are based on California jurisdictional rate base.

| Return on Rate Base ($ billions) | | | | | | |
|---|---|---|---|---|---|---|
| | **PG&E** | **Δ %** | **SCE** | **Δ %** | **SDG&E** | **Δ %** |
| **2016** | $1.56 | - | $1.48 | - | $0.31 | - |
| **2017** | $1.52 | -2.56% | $1.59 | 7.43% | $0.32 | 3.23% |
| **2018** | $1.52 | 0.00% | $1.59 | 0.00% | $0.33 | 3.13% |
| **2019** | $1.47 | -3.29% | $1.80 | 13.21% | $0.36 | 9.09% |
| **2020** | $1.67 | 13.61% | $1.96 | 8.89% | $0.38 | 5.56% |
| **2021** | $1.66 | -0.60% | $2.15 | 9.69% | $0.42 | 10.53% |
| **2022** | $1.67 | 0.60% | $2.30 | 6.98% | $0.48 | 14.29% |
| **Annual Average Δ** | | **1.29%** | **-** | **7.70%** | **-** | **7.63%** |

# 2023 IOU Capital Structure and ROR

- The CPUC establishes weighted average cost of capital and **authorized ROR** for each IOU by setting the percentages of long-term debt, preferred stock, and common stock to total capital that the utility should use to finance rate base, and the cost of each component.
- The percentages (capital structure) on average are **52% equity, 45% debt** with a small weighing for preferred stock.
- **PG&E** - A **1% increase in ROR = $450 million for 2023**. This is dependent on the amount of rate base.

| Utility | Cost of Common Stock (ROE) | Cost of Long-term Debt | Cost of Preferred Stock | Overall Cost of Capital (ROR) |
|---|---|---|---|---|
| **SCE** | 10.30% | 4.74% | 5.70% | **7.68%** |
| **PG&E** | 10.25% | 5.16% | 5.52% | **7.81%** |
| **SDG&E** | 10.20% | 4.59% | 6.22% | **7.55%** |
| **SoCalGas** | 10.05% | 4.23% | 6.00% | **7.30%** |

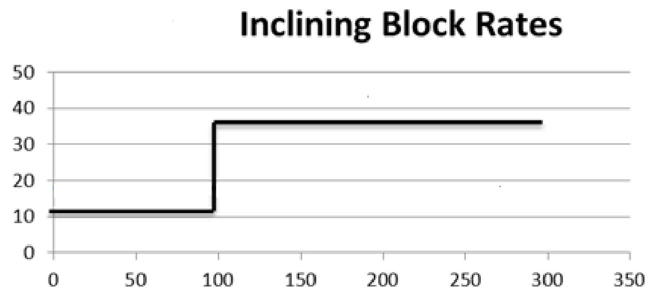
# Electric Rate Design Elements

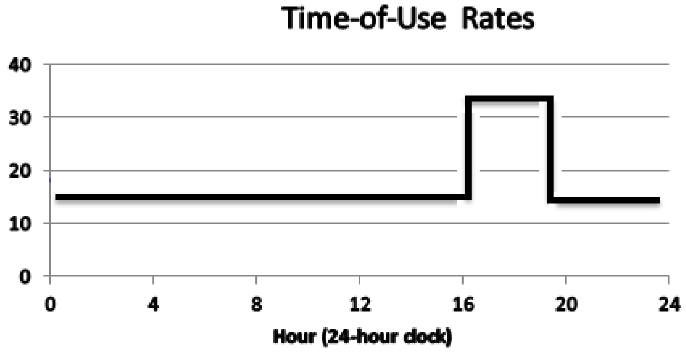
*A Spectrum of Complexity from Flat Charges to Real Time Pricing*

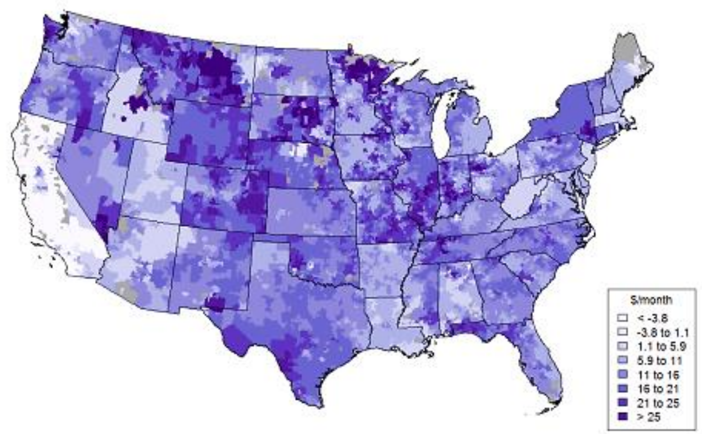
- **Volumetric Charge ($/kWh)**
  - Inclining block rates:  Rate goes up for a higher block, or tier, of energy usage
  - Time-of use (TOU) rates
  - Dynamic or real-time pricing rates

❖ **Demand Charges ($/kW maximum demand)**
  - Reflect capacity cost
  - Non-coincident (applies anytime)
  - Coincident (only applies in peak or part-peak periods)

❖ **Assorted Fixed Charges ($/month)**
  - Includes customer and other costs that don’t vary with usage.




Average Electric Fixed Charge Level by Zip Code Across the US

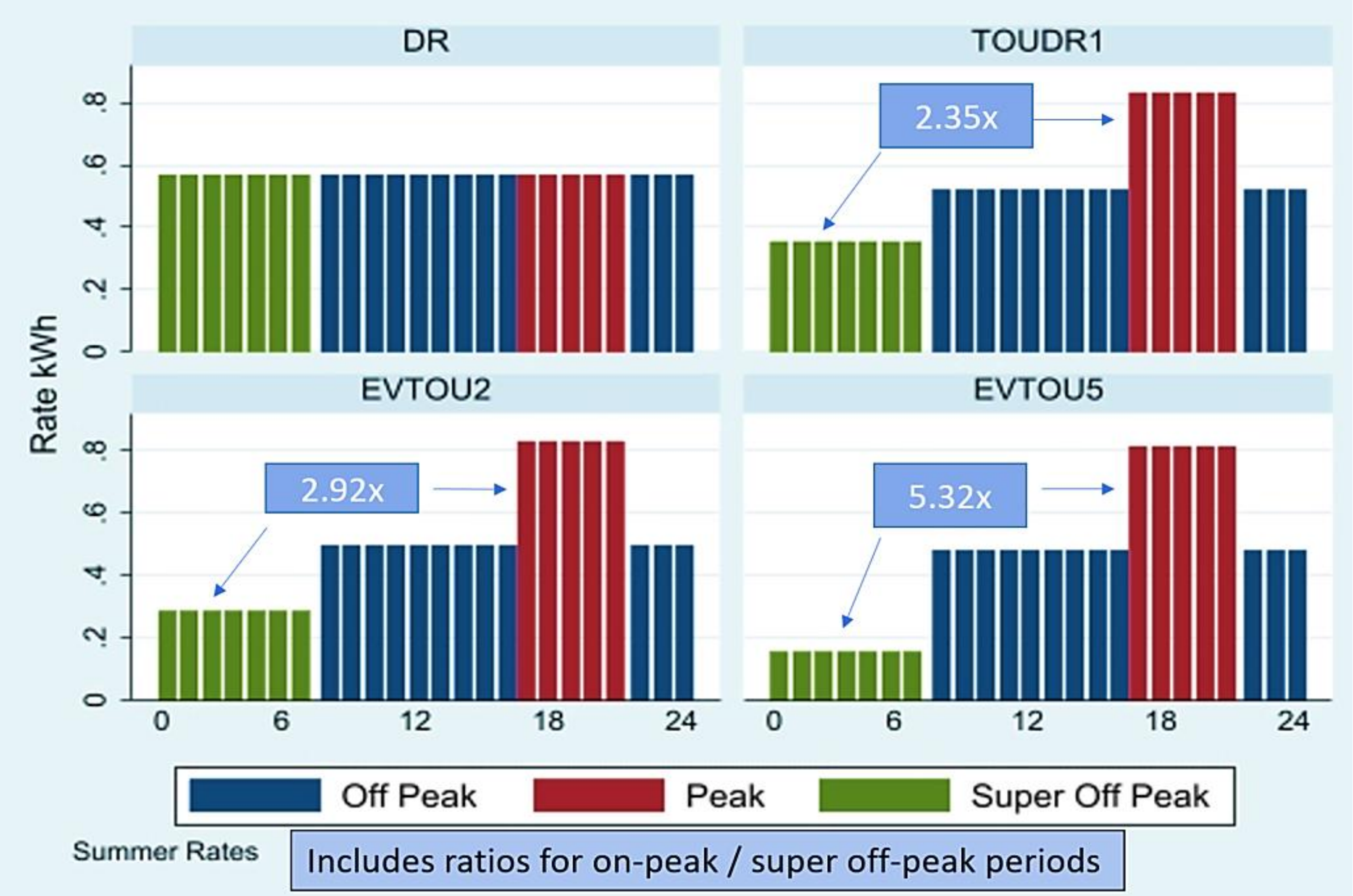
# The Fundamentals of Electric Time of Use (TOU) Rates

- TOU Rates are volumetric rates (in $/kWh) that vary by season, day-type, and time of day (usually 2 or 3 periods per day).

- Generally, TOU pricing is intended to reflect the tendency of certain groups of hours to be high- or low-cost hours, providing a **price signal** to shift load.

- Most TOU rates have peak periods from 4 pm – 9 pm or 5 pm - 8 pm.

**SDG&E Illustrative Example:**
**Summer Pricing as of January 1, 2023**



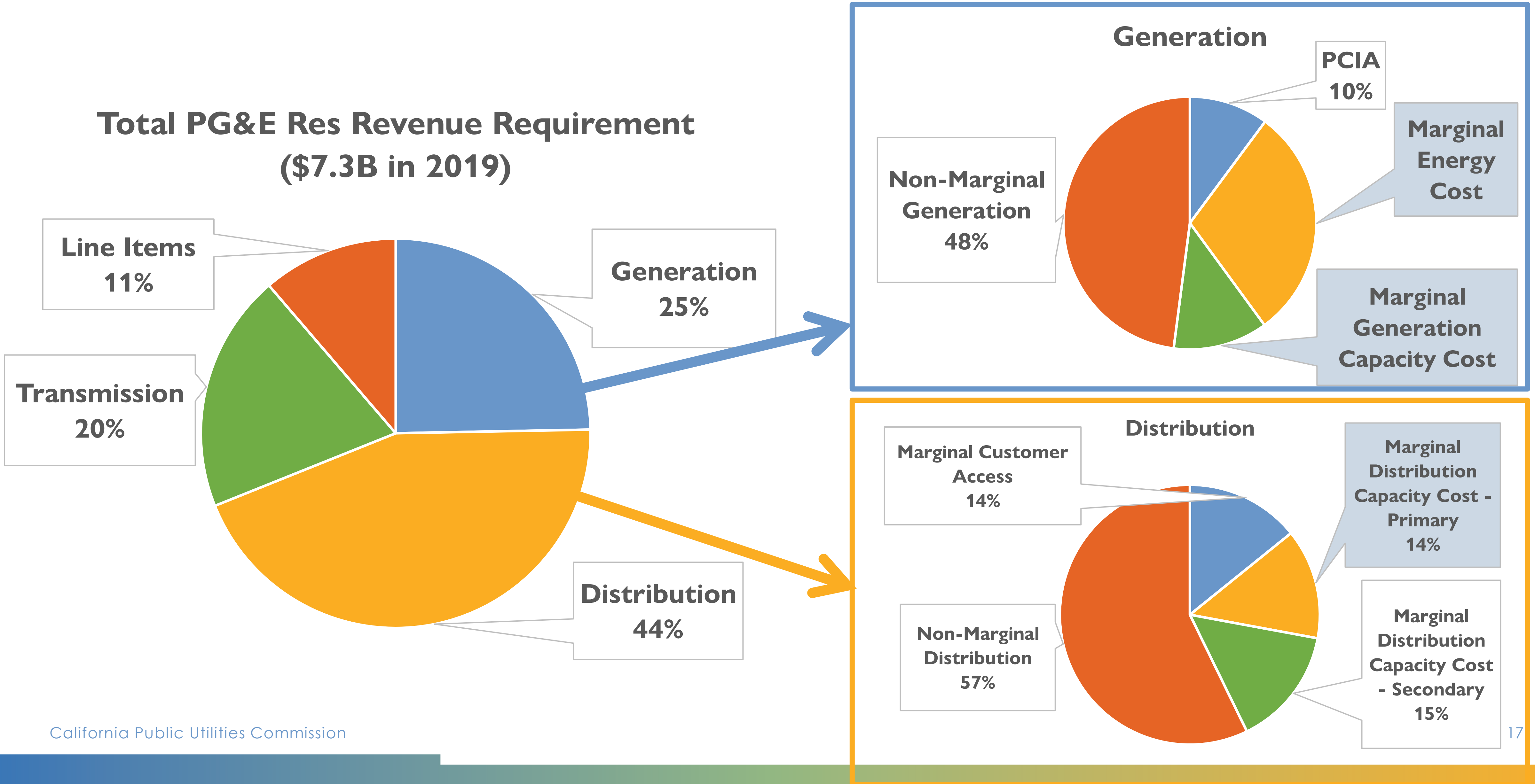
# Dynamic Rates & Real Time Pricing Basics

- Dynamic rates send price signals, sometimes at short notice, to reduce usage in response to grid conditions.

- **Critical Peak Pricing (CPP)** is a form of dynamic pricing.
  - ➢ Participating customers get discounted rates in exchange for shifting loads during critical peak hours.
  - ➢ Event hours called up to one day in advance.
  - ➢ *"Critical Consumption Pricing"* would incentivize consumption when overgeneration is high.

- **Real Time Pricing (RTP)** rates are price signals that reflect wholesale electric system conditions on an hourly (or less) basis.
  - ➢ RTP could be based on generation prices (temporal), transmission and distribution prices (locational), or other factors, such as the prior day's temperature.

# "Functionalization" and Allocation of Revenue Requirement



# Impact of Functionalization of RRQ on TOU Rate Design

- TOU Rates are designed based on allocating all ***Peak-Derived Marginal Costs*** to TOU periods via Peak Cost Allocation Methodology
  - For example: In 2019 PG&E's case **only ~17% of total RRQ is allocated on a time-differentiated basis:**
    - 42% of Gen (MEC and MGCC) and 14% of Dist (Primary MDCC)

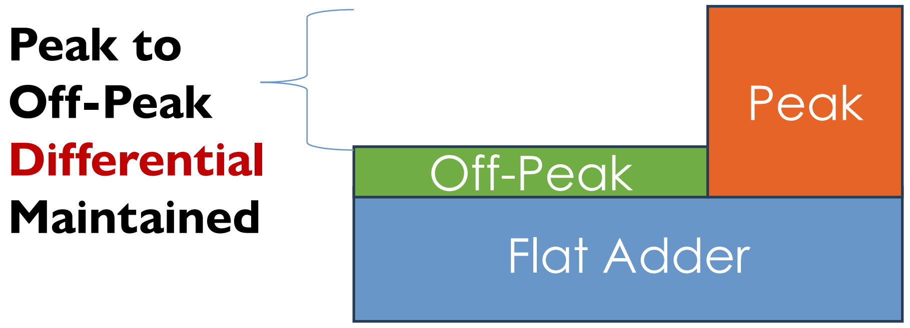
- All Transmission Costs, Line Items, PCIA are allocated on a "flat" or equal-cents per kWh basis ~34%

- **For Residential: Secondary MDCC and MCAC are also collected on a flat basis ~13%**
  - For Non-residential: Secondary MDCC and MCAC tend to be recovered in rates via a size-based measure (Non-coincident demand charge)

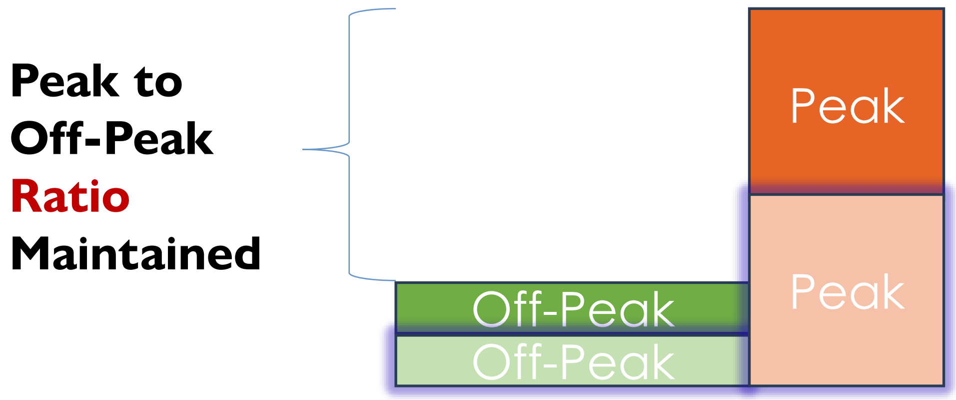
- **What should be done with the "unallocated" or "non-marginal costs"?**
  - Note: This is ~37% of total RRQ

# IOUs Have Different Methodologies for Allocation of "Non-Marginal" Generation and Distribution Costs

- PG&E and SDG&E treat "Non-Marginal" costs as sunk costs and recover these costs on a flat basis, i.e., a **Flat Revenue-Neutral Adder**
- SCE scales all its "Marginal Cost Rates" by scalars so that the **Scaled Marginal Cost Rates are Revenue-Neutral**
- **As a result, SCE's TOU rates tend to have higher Peak to off-Peak differentials.**




**Flat Revenue Neutral Adder**




**Revenue Neutral Scalar**

# Understanding Demand Charges and Commercial Tariffs

- ***Demand Charges*** *are legacy energy charges* ***based on a customer's highest demand during any 15-minute interval measured in a billing period***.
  - ➢ May be a fixed charge per kilowatt and is reflective of the capacity costs caused by each customer.
  - ➢ Feature of non-residential rate design only (at this time).

- Difference between "**demand**" (kW) and "**consumption**" (kWh) -
  - ➢ **Kilowatt (kW) – A unit of electrical power equal to 1,000 watts.**
    - **Demand (Capacity)** – Average rate at which electricity is consumed during a 15-minute interval.
  - ➢ **Kilowatt-hour (KWh) – 1 kW used for one hour.**
    - **Consumption (Energy)** – Amount of electricity consumed over a period of time (i.e., billing period).

- **Coincident Demand Charge (CD)** is a customer charge assessed during the system peak.
- **Non-Coincident Demand Charge (NCD)** is a customer charge reflecting the customer's highest 15-minute interval of kW demand in a monthly billing cycle.

# Why Load Factors and Demand Charges Matter

**Load Factor = (Average Demand / Peak Demand) x 100%**

- **A "High" Load Factor customer has a usage profile is relatively consistent across all hours.**
  - E.g., a large industrial customer who is always using 5MW of electricity
- **A "Low" Load Factor customer** is one whose usage profile can vary significantly and may only use electricity at their peak demand during a few hours of the day
  - E.g., a "peaky" residential customer with AC, also an EV charging station

- **High Load Factor customers may prefer higher demand charges since this leads to lower overall per-unit energy costs.**
  - Certain utility equipment (e.g., Final Line Transformers and Service Drops) must be sized to meet each customer's individual peak demand.
  - Ensuring an appropriate balance between (per-kW) demand charges and TOU (per-kWh) energy charges is important to provide incentives to shift energy use to **system** off-peak periods while still fairly charging for **customer-specific** costs.

# The Income Graduated Fixed Charge ("Flat Rate") and Ratepayer Benefits

Presenter: Clinton Chan

# Why Was AB 205 and the Income Graduated Fixed Charge (IGFC) created?

- **Reason 1 - Support low-income customers with cost shifts:** Residential energy bills are rising, and residential solar has displaced some fixed costs to low-income customers who can't afford solar and remain reliant on the grid. A fixed charge allows all customers to pay their share of fixed costs.

- **Reason 2 - Fixed costs don't vary with usage:** AB 205 acknowledged that there are some fixed costs (e.g. public purpose programs like CARE) from the grid that don't vary with usage. Capturing this in a fixed charge creates some revenue stability for IOUs

- **Reason 3 – Beneficial electrification for all customers:** As we move toward a high DER future, a fixed charge followed by lower volumetric rates based on usage can incentivize all customers to purchase technologies like heat pumps and EVs without worrying about their bill rising drastically. Lower-income customers especially have a hard time electrifying

# Key Provisions of AB 205 and IGFC Implementation

- **Implementation of IGFC: Q4 2025 (SCE and SDG&E), Q1 2026 (PG&E)**
  - Ongoing ME&O program implementation and verification system development starting Q3 2024.

- Removes the prior cap of $10/month on fixed charges in default residential rates.

- Allows CPUC to authorize fixed charges in residential rates such that:
  - Fixed charges are income-graduated with a minimum of three income thresholds
  - **Resulting bills for low-income ratepayers in each baseline territory (climate zone) must be lower without any changes in usage (or see a bill reduction based on average use).**

- Allows recovery of public purpose program non-bypassable charges through fixed charge (e.g. NEM).

- Adjusts definition of CARE effective discount such that **CARE-exempt charges are incremental to discount.**

- **Decision 24-05-014 authorized an IGFC for default residential rates in May 2024.**

# Summary of the IGFC Structure Adopted in Decision

- **Three income tiers:**
  - Tier 1 – CARE (California Alternative Rates for Energy) -eligible customers
  - Tier 2 – FERA (Family Electric Rate Assistance) -eligible customers plus customers who live in deed-restricted affordable housing
  - Tier 3 - Non-CARE/FERA-eligible customers

- **Recover marginal customer access costs + specific line items, capped at current SMUD fixed charge. Discounted fixed charges for CARE and FERA customers:**
  - Tier 1 - $6/month
  - Tier 2 - $12.08/month
  - Tier 3 - $24.15/month

- **Volumetric rate reductions across all TOU periods. Summer peak reduction of 8-10% (based on 2023 revenue requirements)**
  - PG&E – $0.437/kWh ($0.047/kWh reduction)
  - SCE – $0.522/kWh ($0.046/kWh reduction)
  - SDG&E – $0.783/kWh ($0.068/kWh reduction)

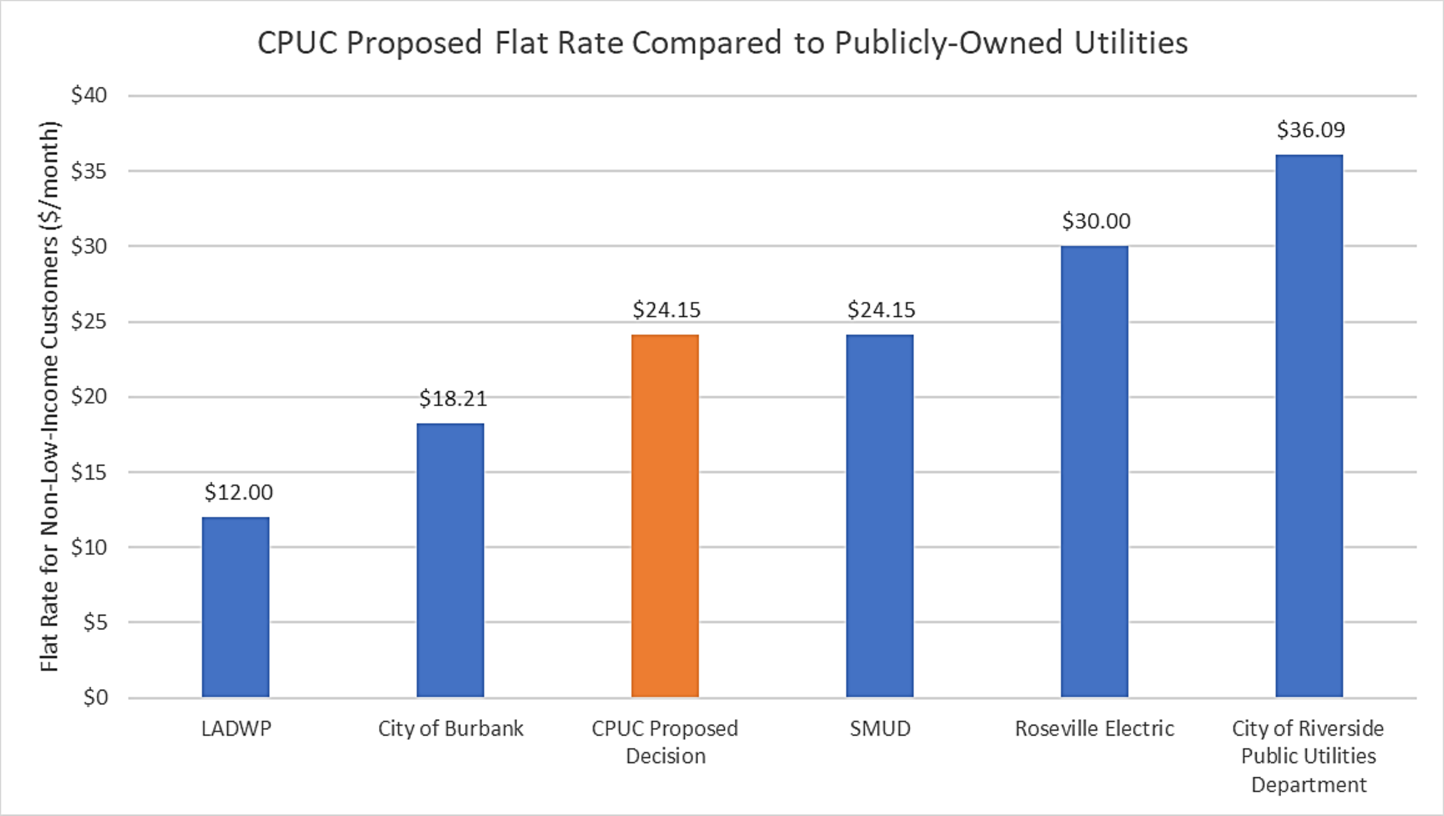
❖ **Optional rates are required to have the same fixed charge structure.**

# Comparison to Party Proposals and POUs

*Proposed IGFC falls in middle of range of parties' proposals and existing fixed charges in California*

| | Non-CARE/FERA Fixed Charge ($/month) | | |
|---|---|---|---|
| | PG&E | SCE | SDG&E |
| SEIA | $ 9.72 | $ 10.11 | $ 13.57 |
| Clean Coalition | $ 12.77 | $ 13.94 | $ 18.51 |
| CEJA* | $ 15.19 | $ 14.61 | $ 14.42 |
| CPUC PD | $ 23.78 | $ 24.15 | $ 24.15 |
| Sierra Club* | $ 28.48 | $ 36.65 | $ 36.44 |
| Cal Advocates | $ 29.96 | $ 31.15 | $ 32.15 |
| TURN/NRDC | $ 30.64 | $ 29.97 | $ 29.70 |
| Joint IOUs | $ 51.00 | $ 51.00 | $ 73.00 |

* Proposal features highly progressive fixed charges with several income brackets; values presented in table represent weighted average



# Each IOU's "Fixed Charge" Includes Different Costs

**The Fixed Charge for each IOU will include 100% of Marginal Customer Access Costs (the cost of connecting customers to the grid).**

- May include Nuclear Decommissioning costs (ND), New System Generation Charges (NSGC or LGC), and Public Purpose Program costs (PPP) (e.g. SGIP).
- How much of each of these cost categories are built into each fixed charge will be at the discretion of IOUs. Each IOU has also proposed to apply a Fixed Charge or CARE discount to ensure the fixed charge doesn't exceed the limit per Tier.
- Cost categories not collected in the fixed charge will likely be collected elsewhere by IOUs (e.g. volumetric rates)
- Other “non-marginal” costs may be picked up via the PPP recovery mechanism if they are deemed reasonable as the IGFC structure evolves.

# IGFC Bill Impacts – Default TOU Rates

*Estimated based on average usage. Savings for low-income customers and hotter climate zones.*

### PG&E Average Monthly Bill Impacts

| Climate Zone | CARE | FERA | Non-CARE/FERA |
|---|---|---|---|
| **P** | $ (8.53) | $(18.09) | $ (4.21) |
| **Q** | $ (6.24) | $(13.61) | $ (2.24) |
| **R** | $ (6.76) | $(14.28) | $ (3.45) |
| **S** | $ (5.74) | $(12.63) | $ (1.47) |
| **T** | $ (0.60) | $ (2.90) | $ 9.11 |
| **V** | $ (2.62) | $ (6.75) | $ 1.64 |
| **W** | $ (6.34) | $(13.48) | $ (1.47) |
| **X** | $ (2.61) | $ (6.70) | $ 3.40 |
| **Y** | $ (7.06) | $(15.43) | $ 2.49 |
| **Z** | $ (4.09) | $ (9.96) | $ 11.50 |

### SCE Average Monthly Bill Impacts

| Climate Zone | CARE | FERA | Non-CARE/FERA |
|---|---|---|---|
| **5** | N/A | N/A | $ 0.82 |
| **6** | $ (1.62) | $ (2.40) | $ 6.41 |
| **8** | $ (2.66) | $ (4.02) | $ 5.13 |
| **9** | $ (4.39) | $ (6.80) | $ 0.43 |
| **10** | $ (7.08) | $(10.86) | $ (0.28) |
| **13** | $ (8.19) | $(12.25) | $ (2.96) |
| **14** | $ (8.36) | $(12.73) | $ (2.12) |
| **15** | $ (9.77) | $(14.94) | $ (6.72) |
| **16** | $ (5.88) | $ (9.25) | $ 4.15 |

### SDG&E Average Monthly Bill Impacts

| Climate Zone | CARE | FERA | Non-CARE/FERA |
|---|---|---|---|
| **Inland** | $ (6.63) | $(10.31) | $ 0.74 |
| **Coastal** | $ (3.78) | $ (5.94) | $ 2.39 |
| **Desert** | $(17.97) | $(27.50) | $ 0.33 |
| **Mountain** | $(19.79) | $(30.89) | $ (6.79) |

# Change in Electrification Bill Impacts

**IGFC lowers the bill impact associated with electrification by reducing the volumetric rate for all customers.**

- Upper table shows change in bill impact a typical customer* can expect if they electrify home appliances** and vehicle, based on modeled energy usage in inland and coastal climate zones.
- Bottom table shows example of change in bill impact for PG&E customer in inland climate zone for vehicle electrification.
- Includes electricity, natural gas, and gasoline bill impacts.

* Non-CARE/FERA customer on default TOU rate
** Space and water heating, kitchen range, oven, and clothes dryer

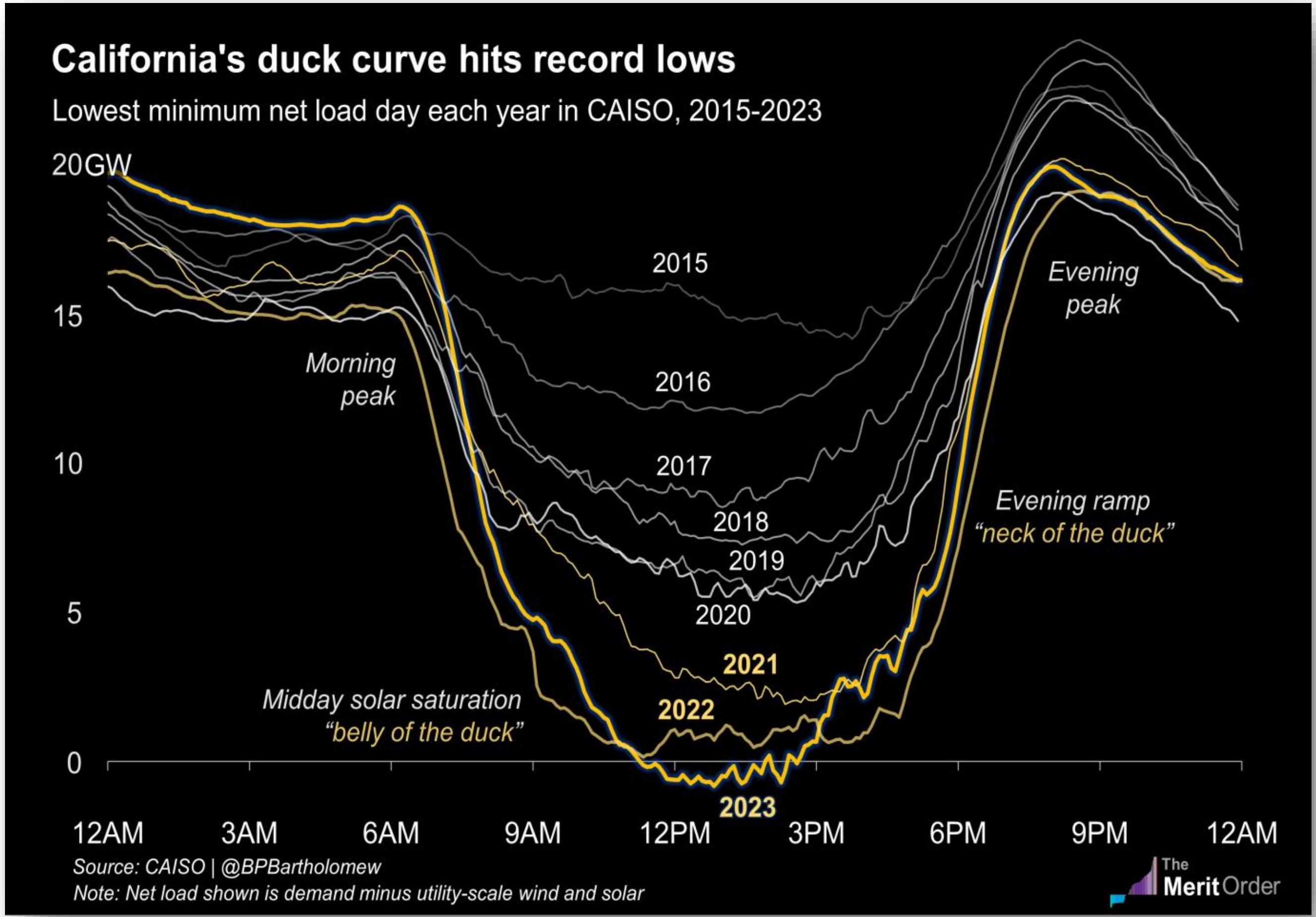
| Change in Bill Impact ($/Month) | | | |
|---|---|---|---|
| **Measure** | **PG&E** | **SCE** | **SDG&E** |
| **Full Home Electrification** | $ (12.05) to (14.19) | $ (11.24) to (12.17) | $ (14.74) to (18.57) |
| **Vehicle Electrification** | $ (17.43) to (17.52) | $ (16.87) to (16.93) | $ (25.11) |
| **Home + Vehicle Electrification** | $ (29.56) to (31.62) | $ (28.17) to (29.04) | $ (39.85) to (43.68) |

| Vehicle Electrification Bill Impact Under Existing TOU Rate (A) | Vehicle Electrification Bill Impact with Fixed Charge (B) | Change in Bill Impact (B) - (A) |
|---|---|---|
| $ 10.86 | $ (6.66) | $ (17.52) |

# California's Electrification and Decarbonization Objectives Require Advanced Pricing Strategies and Reforms

Presenter: Paul Phillips

# California's "Duck Curve" and Evening Ramp Trends Require Greater Precision and Flexibility in Marginal Cost Pricing




## Problematic System Trends Ahead (by 2030)

- Forecasted 60% increase in evening ramp, up to **15-20x increase in inefficient renewable energy curtailment.**
- Demand Response programs have limited impact on shifting load to off-peak times and must be paired with off-peak load growth incentives.
- **Distribution Price Tag for Electrification:** Up to $50 to $100 billion in infrastructure upgrades to ready the grid for mass EV adoption and building electrification.
- **Cause & Effect:** Reliability issues are exacerbated by cost distortions and pricing inefficiency.
- Widespread storage, rapid Vehicle to Grid ("V2G") growth and better pricing are the keys to the future.

# Rapidly Harnessing Demand Flexibility Through Rates Is Critical for Optimizing Grid Management

**California Grid Dynamics Are Changing Rapidly – Expected Trends by 2030:**

- **Doubling of rooftop solar:** 20 GW

- **3.5x growth in BTM storage:**
  - ~ 5.5 GWh storage capacity

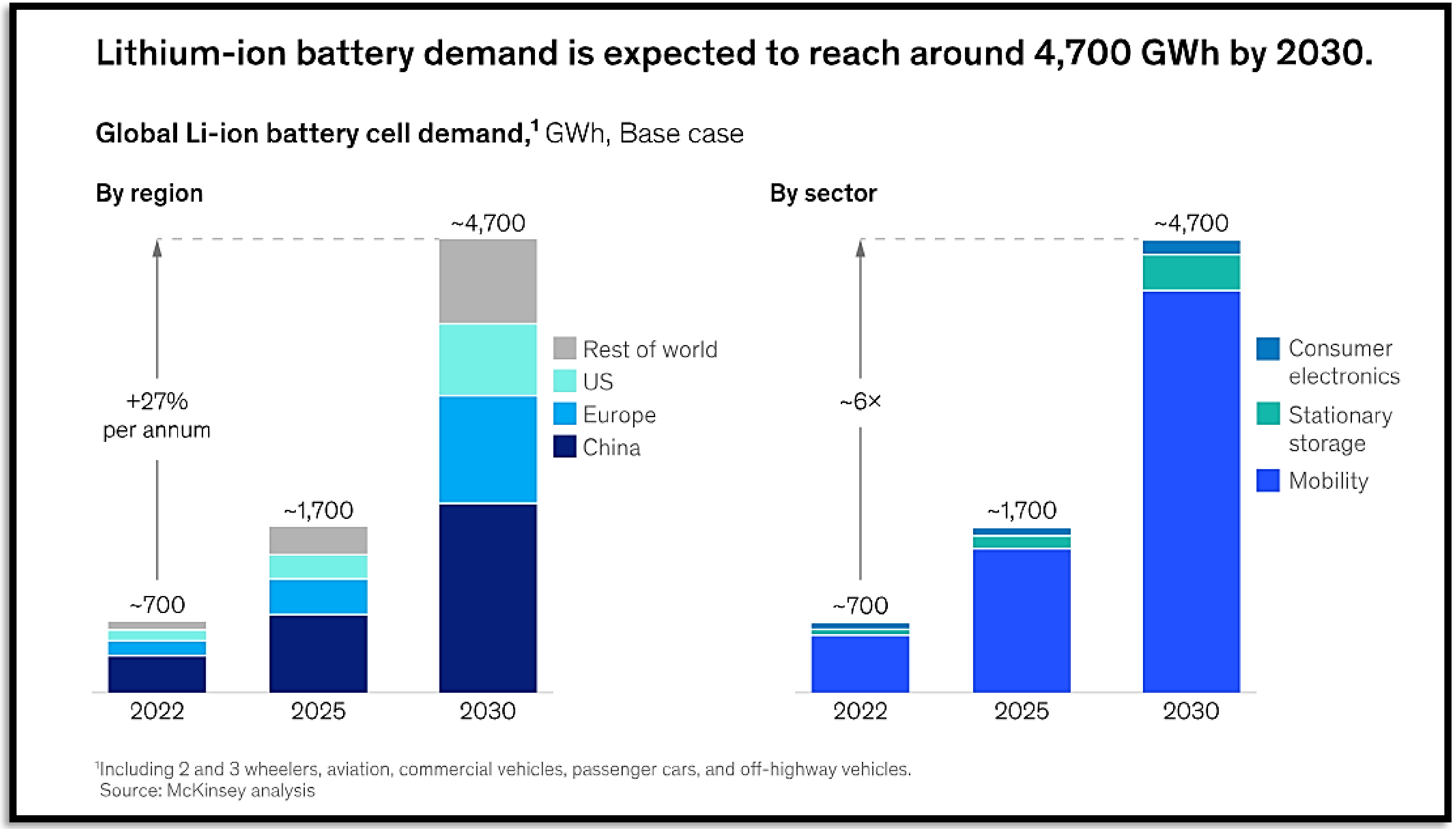
- **Transportation Electrification:**
  - Assuming 5M EVs by 2030 ~ 250 GWh aggregate mobile battery storage
  - **California will end ICE Vehicle Sales by 2035**

- **Building Electrification and Decarbonization:**
  - Next gen programmable thermostats
  - Smart electric heat pump water heaters
  - Smarter devices, appliances, plugs.

- **Growth of microgrids, virtual power plants, and other sources of flexible end uses.**

❖ **Increasing reliability, resiliency and affordability challenges by 2030…**

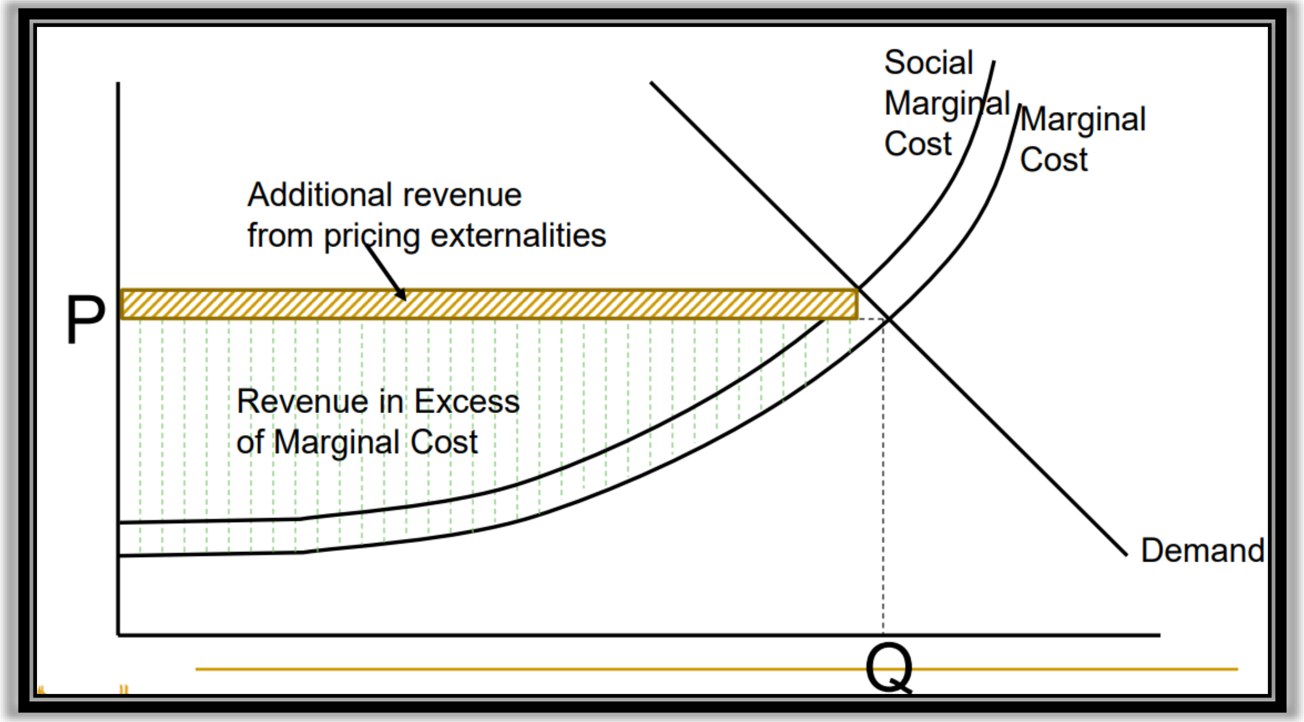
# Mobility and Stationary Storage Sector Demand Presents An Opportunity for Electric Load Growth and Lower Costs




- ~ 6x increase in forecasted global lithium ion demand from 2022-2030.
- Cultivating load flexibility and growth during off peak hours is critical for grid reliability and affordability.
- Global auto tech and convergence in transportation and building electrification (electric EVs/AVs) can greatly lower costs for customers.
- But – we have to liberate electric pricing structures and start measuring cost savings with more precision.

# Increasingly Efficient Pricing and Targeted Load Growth Is Essential for Stable Revenue Recovery and Lower Cost of Service System-Wide

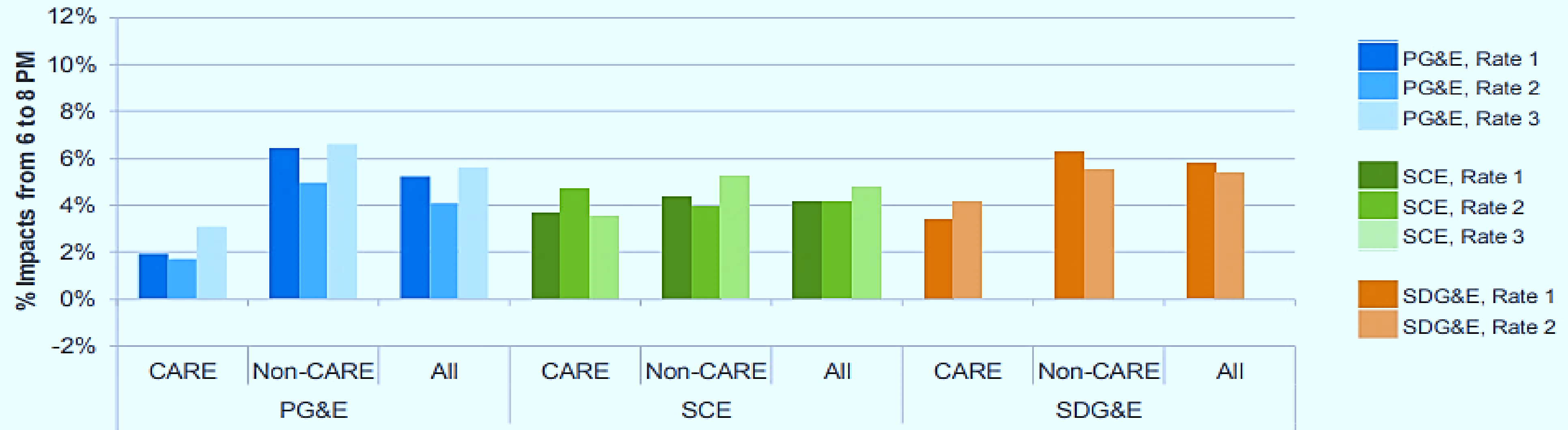
- The revenue recovery above MC (including externalities) varies with hourly shifts in demand and the incremental cost of production of electricity.
- **Social Marginal Cost (SMC)** incorporating externalities is more accurate, but volatile in terms of revenue stability.
- Sales decline due to solar adoption can lead to **revenue shortfall** and cost shift (e.g. NEM tariff).
- There is some debate about which costs beyond distribution / grid access (e.g. CARE) are "fixed".
- This leads us to fixed cost recovery mechanisms: **demand and fixed charges, and subscriptions.**



# Results of “Mild” TOU Rates Boost Confidence in Prospective “Spicy” TOU and Demand Flexible (Dynamic) Rates

➢ ***2022-23 Load Impact Studies:*** *Residential and EV TOU rates yield promising load shift and bill impacts.*

- **Residential TOU**: 2% – 7% interior peak (6-8 pm) load shift, but 1.2% to 7.7% from 4-9 pm.
- **EV TOU Rates**: 14-20% for SCE, 14.7% for SDG&E, and 10-16% for PG&E.



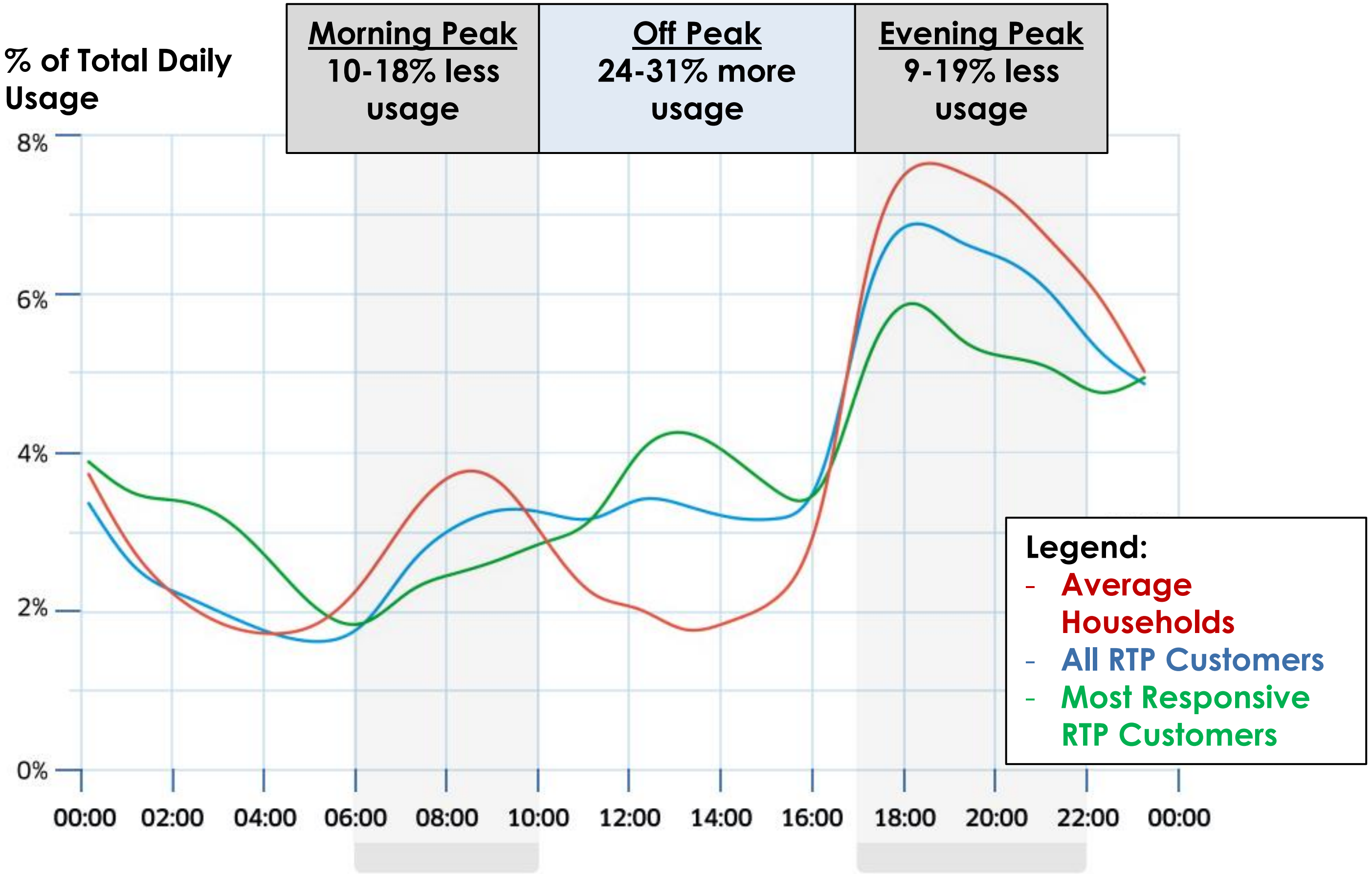

Territory Wide

| | | PG&E CARE | PG&E Non-CARE | PG&E All | SCE CARE | SCE Non-CARE | SCE All | SDG&E CARE | SDG&E Non-CARE | SDG&E All |
|---|---|---|---|---|---|---|---|---|---|---|
| Rate 1 | % Impact | 2.0% | 6.5% | 5.2% | 3.7% | 4.4% | 4.2% | 3.4% | 6.3% | 5.8% |
| | kW Impact | 0.02 | 0.07 | 0.06 | 0.04 | 0.06 | 0.05 | 0.02 | 0.05 | 0.05 |
| Rate 2 | % Impact | 1.7% | 5.0% | 4.1% | 4.7% | 4.0% | 4.2% | 4.1% | 5.6% | 5.4% |
| | kW Impact | 0.02 | 0.06 | 0.05 | 0.05 | 0.05 | 0.05 | 0.03 | 0.05 | 0.04 |
| Rate 3 | % Impact | 3.1% | 6.6% | 5.6% | 3.5% | 5.2% | 4.8% | | | |
| | kW Impact | 0.03 | 0.07 | 0.06 | 0.04 | 0.07 | 0.06 | | | |

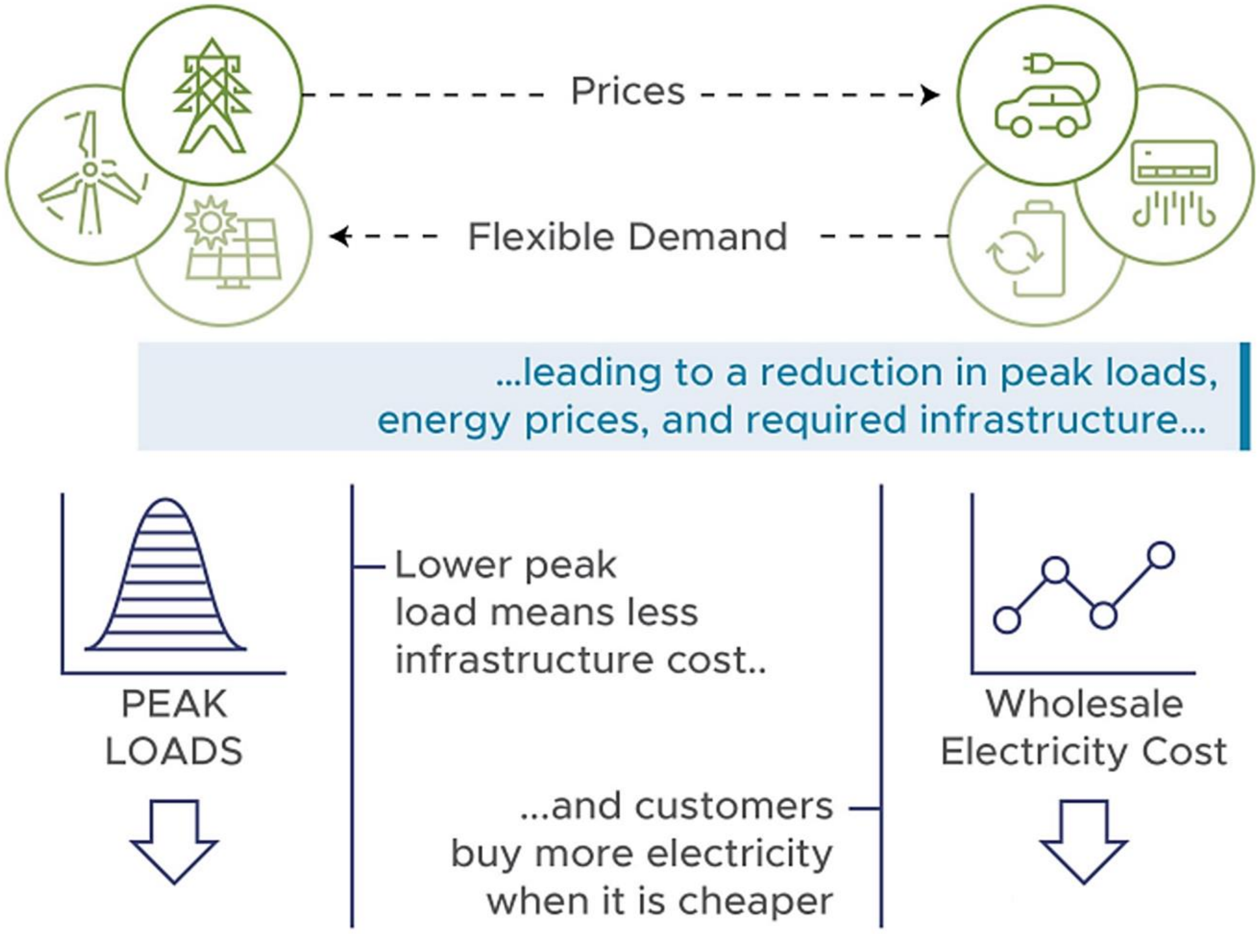
# Residential Dynamic / Real Time Pricing Successes in Other Jurisdictions

- **Domestic and International**
  - **Oklahoma Gas & Electric and Georgia Power:** RTP + baseline subscriptions.
  - **Illinois:** Ameren and ComEd (Illinois) – 13% average residential bill reduction on RTP.
  - **Denmark, Netherlands, Spain:** success with optional to default dynamic / RTP tariffs.
    - ***Netherlands**: 19% peak to off-peak load shift on average in 2023*
    - *Based on 100,000+ users on ANWB Energie's dynamic rate.*
- Growing recognition of the need to expose diverse customer classes to dynamic / RTP signals to maximize demand flexibility.
- Higher risk and reward, third party EMS options.

**Netherlands Hourly Load Shift on Dynamic Pricing Contracts**



# Increased Demand Flexibility Means Higher Capacity Utilization and Downward Pressure on Cost




- ➔ Better alignment of wholesale and retail costs.
- ➔ Reduced peak loads, energy prices, and infrastructure needs (deferred investment).
- ➔ Improved utilization of existing capacity (higher load factors).
- ➔ Reduced cost of service.
- ➔ More ***"prosumer" surplus*** for participating customers.

Image Source: PNNL DSO+T Study January 2022

# Dynamic Pricing Strategies for Meeting California's Future Grid Challenges

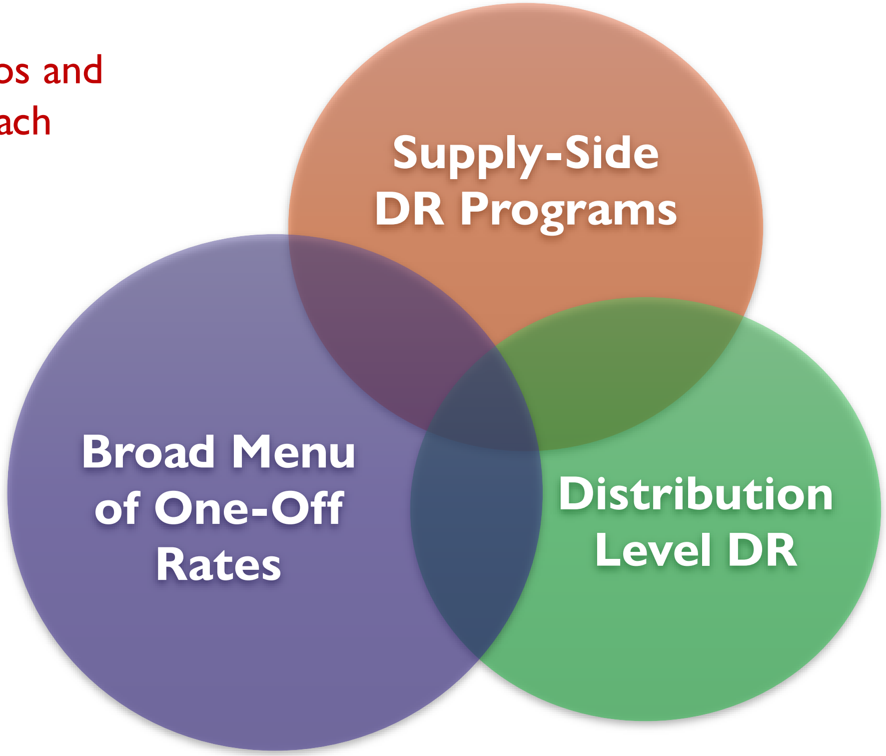
1. **Consolidate the Multiplicity of Time-Variant Rates**
   - Too many one-off special purpose rates: TOU, CPP, EV, Option R/S, Self Gen Incentive Program GHG signals, etc.
   - Retail market complexity warrants scalable rate solutions.

2. **Create Widespread Hourly Rates to Improve Capacity Utilization and Lower Long Run Marginal Costs**
   - Customers from commercial to residential are leaving *prosumer surplus* on the table due to inefficient pricing.
   - Several successful pricing pilots with varying treatment group sizes – from TOU to real time pricing along the spectrum of complexity.

3. **Caveats:**
   - **Load shapes, demand elasticities and geography matter:** "peakier" (low load factor) residential customer performance varies.
   - **Manage Expectations:** Not all customers are good candidates.
   - **Equity:** Participation + level playing field for fixed cost recovery.

# Why CalFUSE? Optimizing DER Value, Maximizing Economics of Electrification, and Improving Grid Resource Management

**Status Quo**: Silos and Piecemeal Approach




- Complex, inefficient, expensive, confusing
- Difficult to scale, limited adoption, obsolescence
- High cost of controls and automation
- Experimental one-off tariff and program designs

**Innovation**: Integrated Price Signal to Incentivize Electrification, Optimize DERs and Virtual Power Plants, Reduce Cost of Service, Meet LMS Standards

**California Flexible Unified Signal for Energy (CalFUSE)**

➔ Reduced complexity, single point of focus
➔ Highly scalable integrated program + tech growth
➔ Lower cost of controls, automation, infrastructure
➔ Widespread advanced TOU and dynamic pricing

# Broad Conceptual Elements of the CalFUSE Framework

**Price Presentation**

- **Universal Standardized Pricing Access** (TOU to RTP)
- **Interconnection with MIDAS** backbone + "price machine" systems
- **Digitization** of other open source grid systems to promote pricing ubiquity

**System Wide Rate Reform**

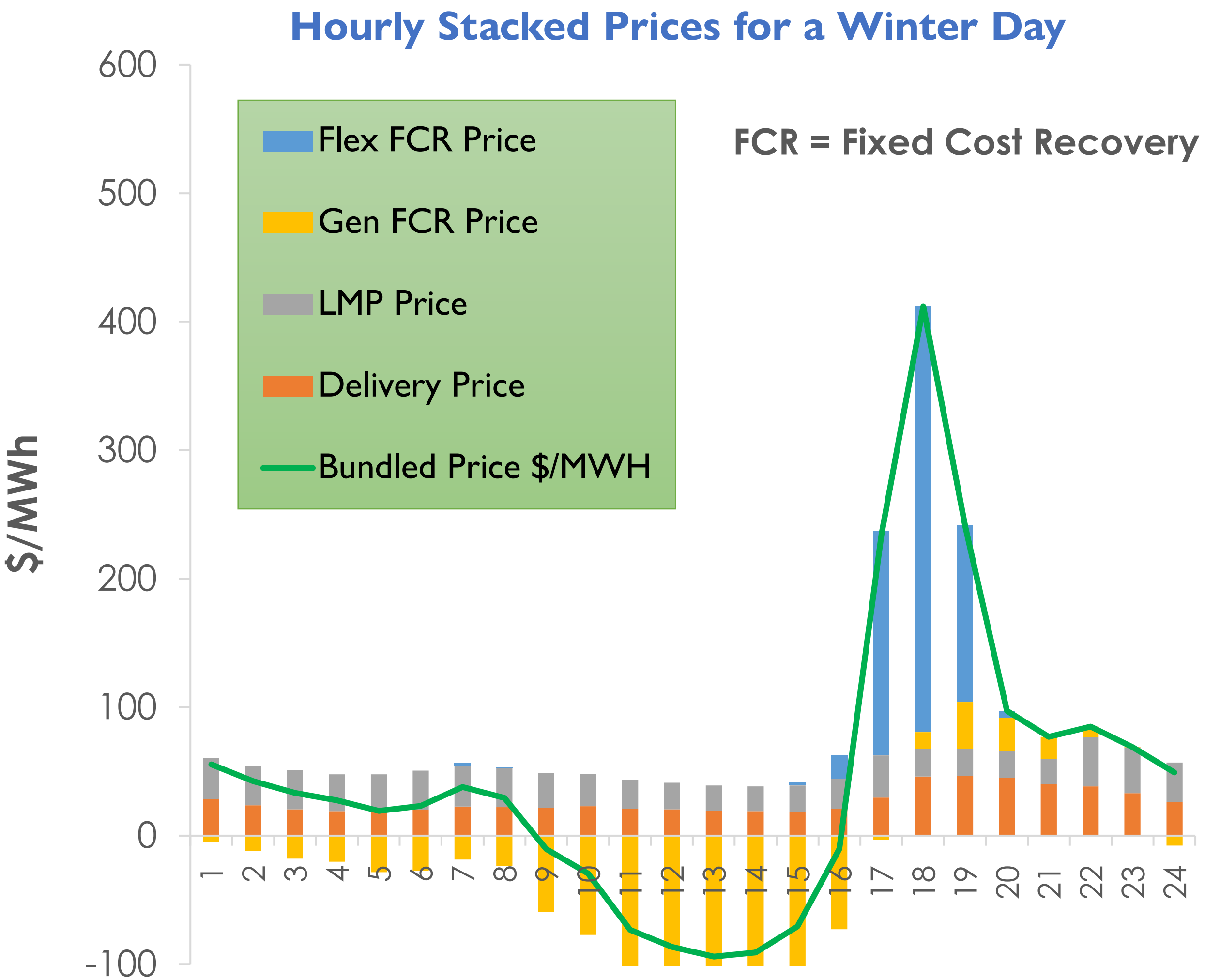
- **Real Time Energy Prices** (marginal energy cost)
- **Real Time Capacity Prices** (scarcity price functions)
- **Location-based Distribution Pricing** (nodal / p-node)
- **Bidirectionality of Pricing** (fair compensation for DER exports)
- **Rate Case Reform** (capacity efficiency adjustments, rate design evolution, equity)

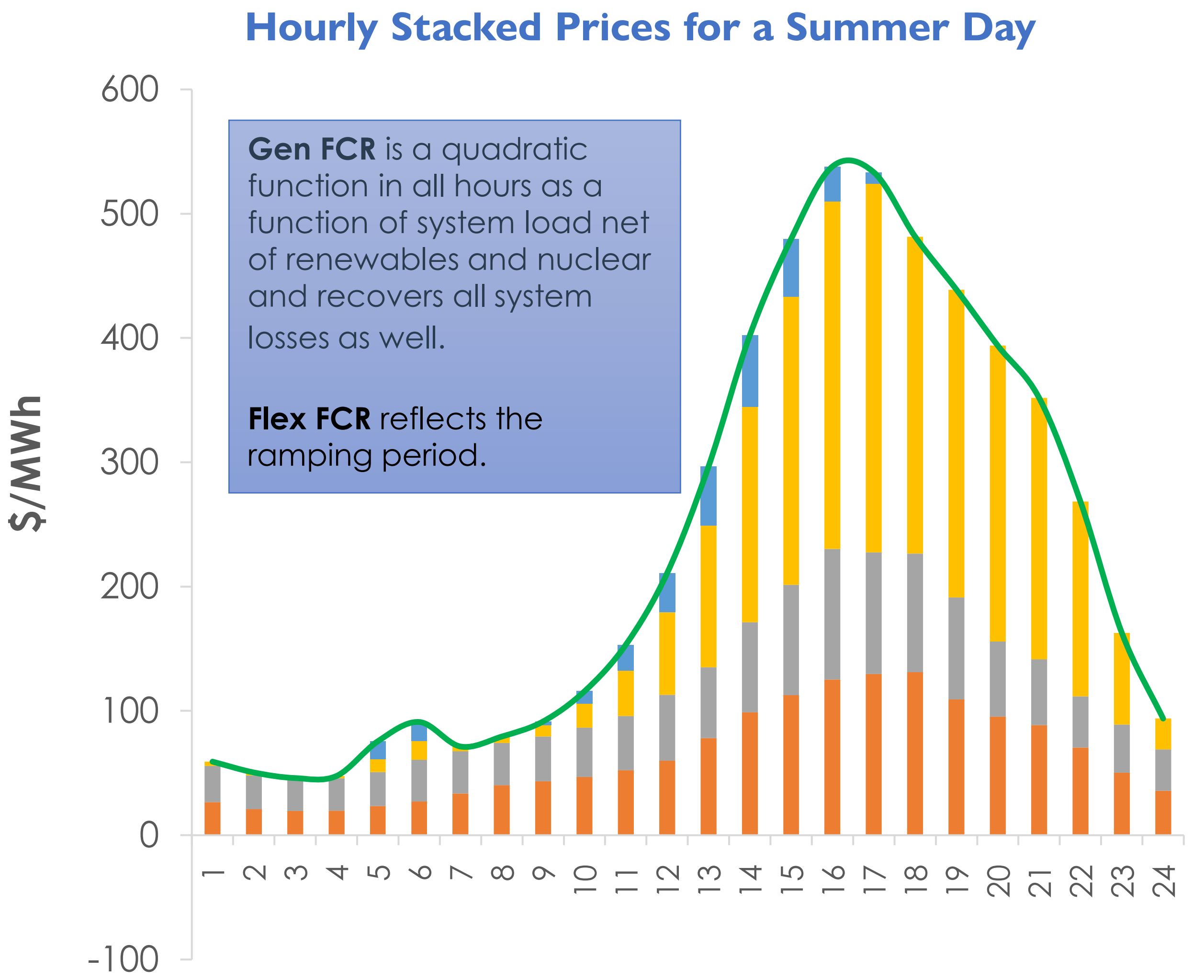
**Hedging Options and Protections**

- **Subscription Options** → "Pay for Your Load Shape"
- **Transactive Energy Options** (week ahead, "buy / sell" contracts)
- **Third Party Energy Management Services** (EMS + ASP marketplace)

# Edison "RATES" Pilot Concept: Hourly Gen and Distribution Price Functions

*Composite Hourly Prices based on Hourly Capacity Utilization & CAISO Locational Marginal Price (LMP)*



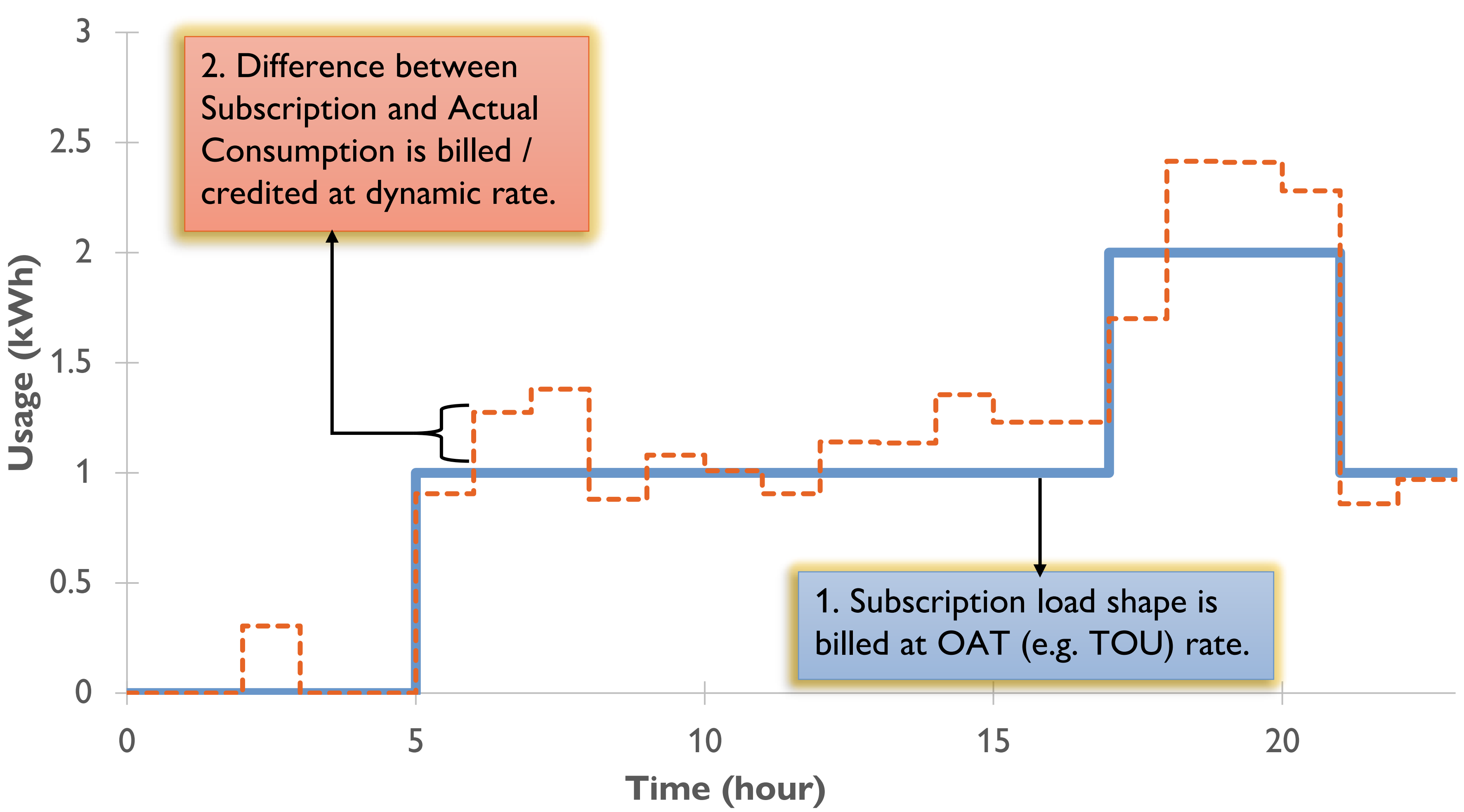






Source: SCE / TeMix "RATES" Pilot funded by CEC (EPIC)

# Customer Protection: Baseline Subscriptions

*Historic Load Shape & Energy Quantity at Otherwise Applicable Tariff (OAT) Price*




- **Stabilizing element (hedge) for customers and utilities.**
- **Ongoing shadow bill with the ability to improve "billing position" at hourly price over OAT.**
- **A form of "paying for your load shape" in advance based on usage history.**
- **Georgia Power has long used customer baseline subscriptions with RTP.**

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