PCIA Rulemaking Workshop 2

Joint Utilities' Presentation
January 16, 2017

Outline

Introduction

- OIR guiding principles and legal requirements
- Review of the IOUs' ongoing cost responsibilities

Flaws in the Current Methodology

- Review of historical context
- Mathematical proof of what is required for indifference
- Impact of using administratively-set benchmarks on bundled service rates
- Impact of using administratively-set benchmarks on procurement decisions

Descriptions and Data-Based Comparison of Potential Solutions

- Direct allocation of portfolio costs and benefits to CCAs and ESPs
- Current methodology with "true-up" of benchmarks
- Buy-out of obligation
- Assignment of IOU contracts to CCAs and LSEs

Conclusion

- Matrix of Results

Principles for Going-Forward Solutions

Scoping Memo Section 2.1

- Bundled IOU customers should be neither worse off nor better off as a result of customers departing the IOU for other energy providers ("bundled customer indifference")
- Transparent and verifiable, including the most open and easily accessible treatment of input data, while maintaining confidentiality of market-sensitive data that must remain confidential
- Reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon
- Flexible enough to maintain its accuracy and stability if the number of departing customers changes significantly
- Not create unreasonable obstacles for customers of non-IOU energy providers
- Consistent with California energy policy goals and mandates

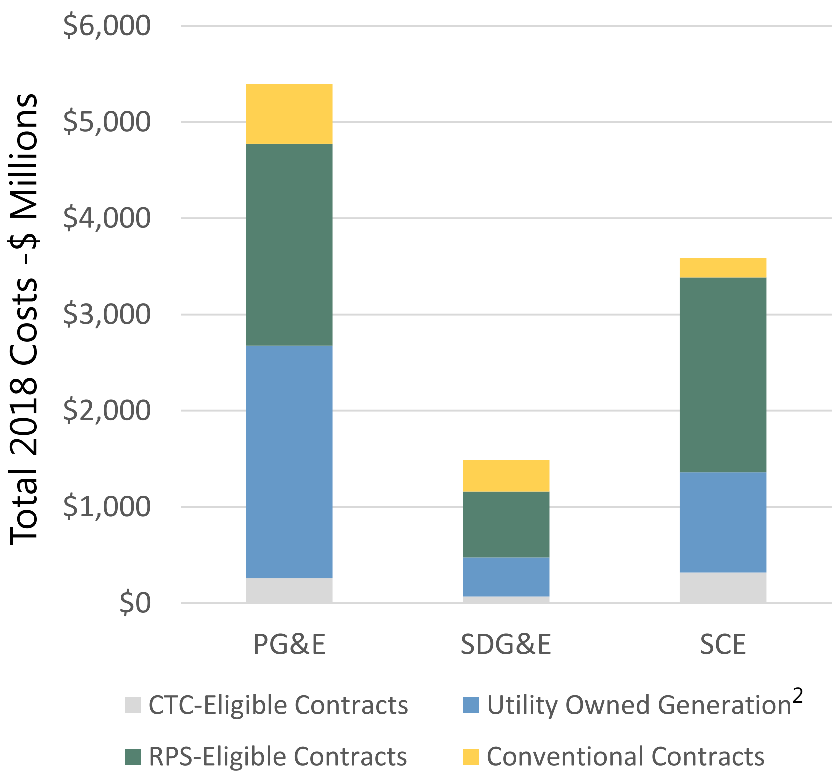
Public Utilities Code Sections 365.2 and 366.3

The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of:

- retail customers of an electrical corporation electing to receive service from other providers (365.2).
- the implementation of a community choice aggregator program (366.3).

The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load (366.3).

Historical IOU Generation Portfolio "Snapshot"[1]



- Historical IOU portfolios were procured/built for all "then-bundled service" customers consistent with 366.3
  - All resources were built/procured pursuant to CPUC approval or an approved procurement plan, selected using the "least cost and best fit" criteria, and approved by the Commission through a rigorous regulatory process that involved numerous stakeholders
- Historical portfolio obligations "taper down" as contracts expire
  - RPS-eligible contracts typically range between 10 and 25 years in length
  - Most conventional contracts expire within the next five years
  - Utilities have proposed that PCIA (or its successor)-recovery for UOG ends when all contracts in the vintage portfolio expire

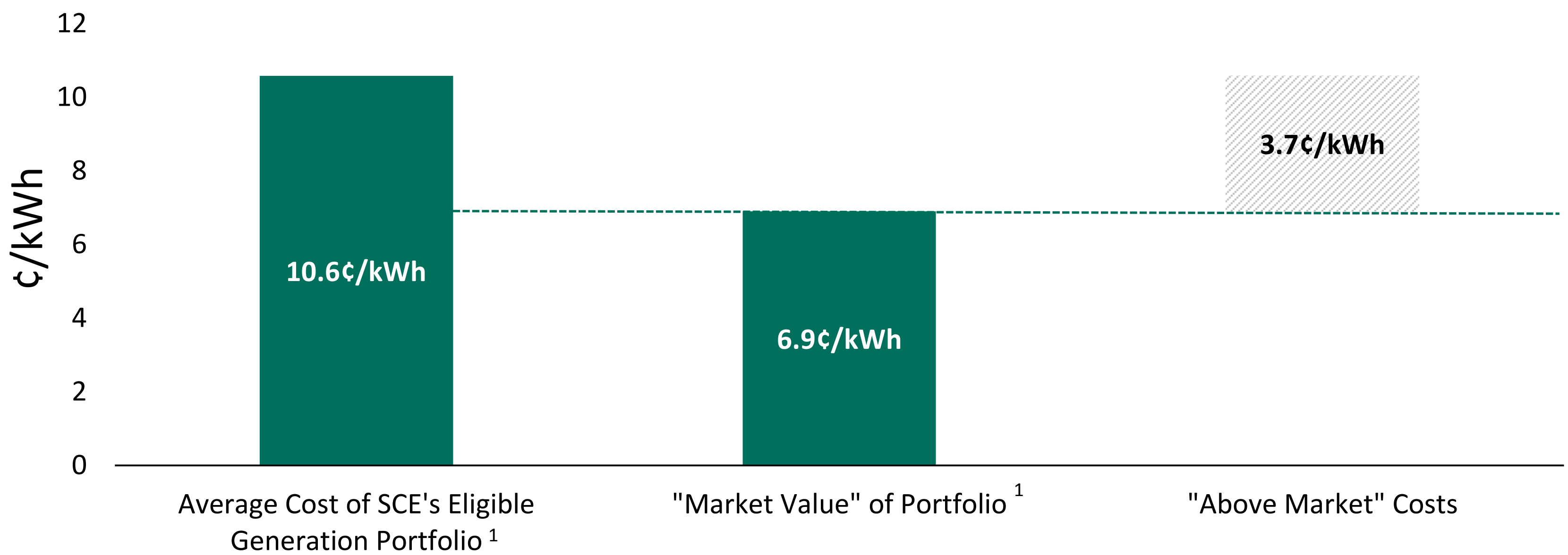
1 Customers are only responsible for the resources that were procured/built prior to their departure. Snapshot is based on each IOU's current portfolio of online resources, and does not include the forecast costs of signed resources that are not yet online (PG&E: ~$46M; SDG&E: ~$20M; SCE:~$300M), nor does it include CAM costs

2 SONGS Settlement Revenue Requirement is included in SCE and SDGE's UOG category

Review of Current Methodology

Akbar Jazayeri, SCE

Current Cost Responsibility Framework



- Customers who depart bundled service for a different "Load Serving Entity" (LSE) currently leave their share of the IOU's historical generation portfolio with the IOU
- Any "above-market" costs, as determined using the Commission-prescribed methodology, of resources procured prior to a customer's departure are the responsibility of that customer

[1] Average cost and "market value" based on SCE's 2018 ERRA Forecast November Update

Historical Context for Current Methodology

- The Current Methodology has significantly evolved over time in efforts to:
  - Reduce administrative burden and increase transparency[1]
  - Reflect the current market value of the utilities' generation portfolio in light of evolving market conditions and new regulatory requirements[2]
- The administrative and formula-based approaches for establishing the Renewable and Capacity benchmarks were adopted as interim solutions, and were to be replaced once markets and/or public indices for those products became available[3]
  - There is continued disagreement on the accuracy and efficacy of the Renewable and Capacity benchmarks
- The Current Methodology was established at a time when there was a limited and capped amount of departing load

1 D.06-07-030; D.08-09-012
2 D.06-07-030; D.11-12-018; Resolution E-4475
3 D.11-12-018 at p. 24 for Renewables and p. 30 for Capacity

Definitions

- kWh_B = Bundled Service Usage
- kWh_{DL} = Departing Load Usage
- C_P = Portfolio Cost Subject to PCIA
- G_P = Output of Portfolio Subject to PCIA
- R_1 = Bundled Service Rate (associated with PCIA-eligible portfolio)[1] Prior to Load Departure
- R_2 = Bundled Service Rate (associated with PCIA-eligible portfolio) [1] After Load Departure
- MPB = Administratively-set Market Price Benchmark
- P_{act} = Actual Price Utility Obtains from Selling Departing Load Customers' Share of G_P
- IR = Indifference Rate

1 Inclusion of the IOU's net short position in the formulas would not result in significantly different results (See backup slides)

Formulas

- $R_1 = \frac{C_P}{kWh_B + kWh_{DL}}$
  - **Bundled Service Rate Before Departures:** Portfolio Cost ÷ Load Responsible for Portfolio
- $IR = \frac{C_P - (MPB \ x G_P)}{kWh_B + kWh_{DL}} = R_1 - \frac{(MPB \ x G_P)}{kWh_B + kWh_{DL}}$
  - **Indifference Rate:** (Portfolio Cost – Portfolio's Market Value at MPB) ÷ Load Responsible for Portfolio
  - **Indifference Rate:** Bundled Service Rate Before Departures – (Portfolio Market Value at MPB ÷ Load Responsible for Portfolio)
- $R_2 = \frac{C_P - (P_{act} \ x \ \frac{kWh_{DL} \ x \ GP}{kWh_B + kWh_{DL}}) - (IR \ x \ kWh_{DL})}{kWh_B}$
  - **Bundled Service Rate After Departure:** (Portfolio Cost – Revenues received by IOU for the sale of the Departing Load customers' share of Portfolio – PCIA and CTC paid by Departing Load customers) ÷ Remaining Bundled Service Load
- $R_2 - R_1 = \frac{kWh_{DL}}{kWh_B} \ x \ \frac{G_P}{kWh_B + kWh_{DL}} \ x \ [MPB - P_{act}]$

Observations about the Current Methodology

- Bundled service customer indifference is achieved when $R_2 = R_1$, which only occurs if MPB = P_{act}
  - This **requires** a true-up of the administratively-set MPB to the actual price obtained from selling departing load customers' share of G_P in the market
  - $R_2 > R_1$ (*i.e.*, bundled service rates increase as a result of departing load) when MPB > P_{act} (current situation from the Joint Utilities' perspective)
  - $R_2 < R_1$ (*i.e.*, bundled service rates decrease as a result of departing load) when MPB < P_{act} (current situation from departing load advocates' perspective)
- If MPB is different from P_{act} then harm or benefit to bundled service customers increases as kWh_{DL} increases and when G_P serves a larger portion of system load
- Current methodology resulted in acceptable outcomes when kWh_{DL} was small and frozen and MPB/P_{act} did not include RPS and RA components

Customer Bill Impact of Using "Benchmarks"[1]

Bundled Service Customer Bill Impact = ($/MWh difference btwn benchmark and actual) x (**Portfolio MWh/Vintage Load Responsible for Portfolio**) x Departing Load (MWh) / Remaining Bundled Service Customer Load (MWh)

% Difference Between Benchmark and Actual[2]

30%

% Load Departures	Impact of Understated Benchmark (¢/kWh)	Impact of Overstated Benchmark (¢/kWh)	% Impact on Generation Bill (2018 SCE)
20%	-0.20	0.20	(+/-) 3%
30%	-0.35	0.35	(+/-) 5%
40%	-0.54	0.54	(+/-) 7%
50%	-0.81	0.81	(+/-) 11%
60%	-1.22	1.22	(+/-) 16%
70%	-1.90	1.90	(+/-) 25%
80%	-3.25	3.25	(+/-) 43%
90%	-7.32	7.32	(+/-) 96%
99%	-80.51	80.51	(+/-) 1056%

Any difference between the benchmark and "actual" market value (in either direction) currently is reflected in bundled service customers' bills because there is no "true-up"

1 Correction to December 5, 2017 equation noted in **bold** and reflected in calculation
2 Data is based on SCE's 2018 ERRA Forecast values

Additional Observation: Current Methodology is Contrary to Least Cost Best Fit (LCBF) Procurement Principles

- The current use of a “flat” RA benchmark ($58.27/kW-year, or $4.86/kW-month) is contrary to LCBF procurement on behalf of customers, because it applies the same RA benchmark to all RA MW, regardless of whether or not it is meeting a customer need

<u>For Example</u>

- Assume the utility customers have a 100 MW short position in August only
  - The utility as the procurement agent for its bundled service customers would run an RFO to procure the needed capacity and per Commission oversight apply LCBF principals to the procurement
- The following bids are received in the RFO
  - Year Round offer of 100 MW @ $2/kW-month
  - August only offer of 100 MW @ $25/kW-month

Offers	Description	Contract payments
1	Year Round offer of 100 MW @ $2/kW-mon	=100MW *1000kW/MW x $2 x 12 month = **$2,400,000**
2	August only offer of 100 MW @ $25/kW-mon	=100MW *1000kW/MW x $25 x 1 month = $**2,500,000**

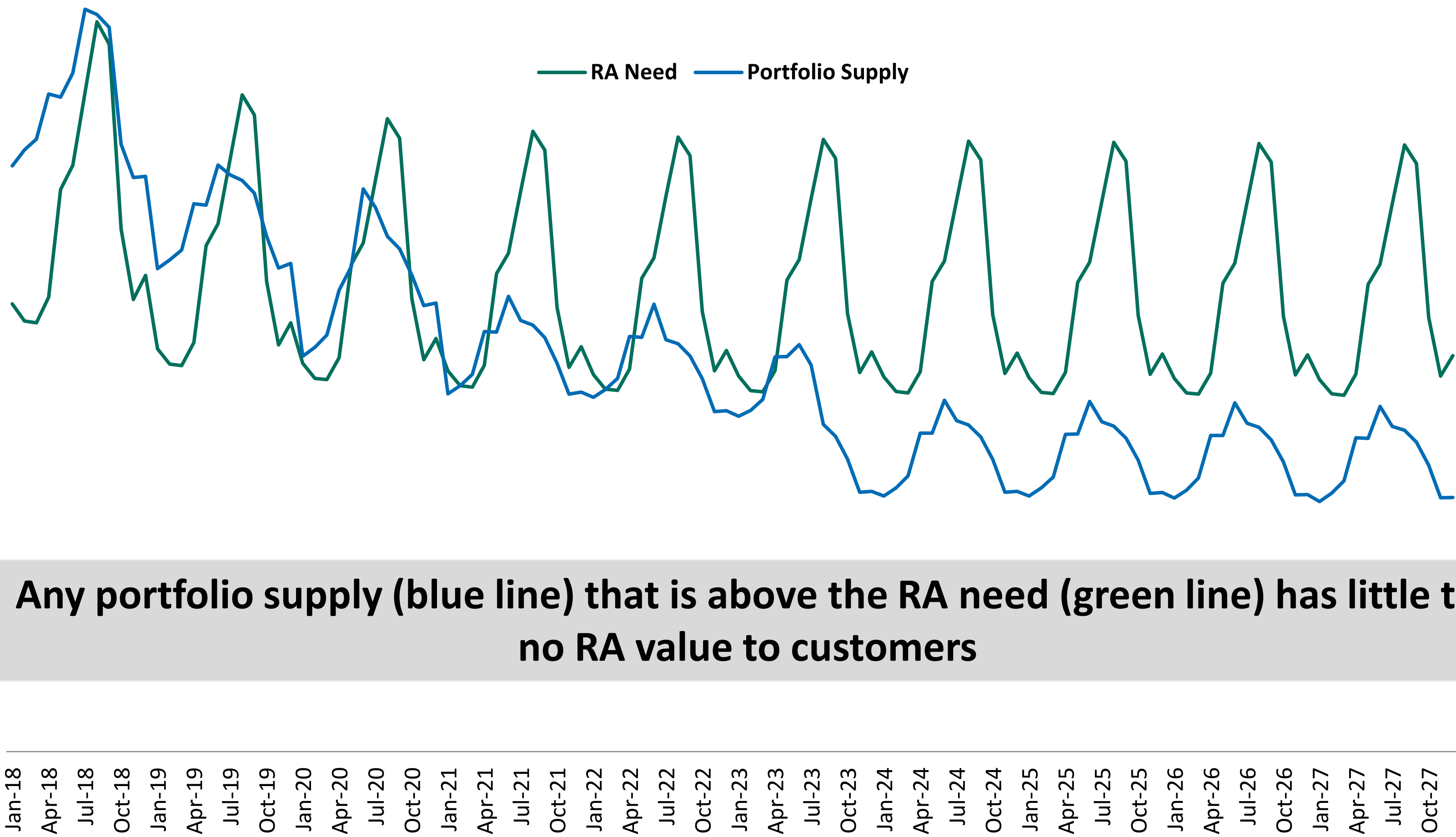
Additional Observation: Current Methodology is Contrary to Least Cost Best Fit (LCBF) Procurement Principles Cont. .....

- Under LCBF principles the lowest cost offer to meet the identified need would be Offer 1 at a total cost of $2.4M
  - Qualitatively from a best fit perspective this offer also provides additional hedge value at no cost for non-August months for RA substitution
  - The additional RA procured in non-August months has little to no RA value from the customer perspective
- However, under the current PCIA methodology, if load were to depart then utility customers would be required to credit departing customers at a rate of $4.86/kW-month for all RA MW-months

Offers	PCIA Credit
1	=100MW *1000kW/MW x ($4.86) x 12 months = **$5,832,000**
2	=100MW *1000kW/MW x ($4.86) x 1 month = **$486,000**

- If this were incorporated into the selection decision then the utility as agent for customers would procure Offer 2 and not Offer 1 leading to a higher cost ($2.5M) for customers at the outset contrary to LCBF

Resource Adequacy Needs



Any portfolio supply (blue line) that is above the RA need (green line) has little to no RA value to customers

Review of "Potential Options"

Ranbir Sekhon

Description of Portfolio Allocation

- IOUs continue to manage the historical generation portfolios on behalf of the customers the portfolios were procured for
- All customers (bundled service and departing load) receive their share of the portfolio benefits
  - Energy and ancillary services benefits will be monetized by the IOU, and market revenues will be used to offset the costs of the resources
  - Resource Adequacy (RA) will be allocated to the customers' LSEs using the existing Cost Allocation Mechanism (CAM) process, and will reduce the LSEs' RA obligation
  - Renewable Energy Credits (RECs) will be transferred to the LSEs' WREGIS account and can be used to meet the LSEs' RPS requirements
    - Contingent upon CPUC approval that allocated RECs retain their Portfolio Content Category and long-term contracting designations
- All customers are responsible for their share of the portfolio "net costs"
  - Initial rates will be based on a forecast of annual costs and market revenues and set in the annual ERRA Forecast proceeding
  - Actual costs, market revenues, and revenues received from customers will be recorded in a balancing account and "trued-up" in the following year's rates.

Key Takeaways:

- All customers (bundled service and departing load customers) contribute the same $/kWh towards the recovery of the resource costs for which they are responsible
- Customers and their LSEs receive the pro-rata share of the portfolios that were procured on their behalf with a methodology that is fully scalable

Description of Current Methodology with "True-Up"

- Customers who depart bundled service continue to leave their share of the IOU's historical generation portfolio with the IOU
- Portfolio costs, output, and market value set on a forecast basis and "trued-up" the following year based on actual market outcomes—this would **require** the following:
  - Readily-available market-index for RPS and RA
  - Robust, liquid, and transparent market for RPS and RA products
  - Recognition of depth of market concerns for RA and RPS, value trends to zero when there is no need
- RPS and RA procurement data from all entities, not just IOUs, will be required given potential load-share of non-IOU LSEs
  - All market sensitive data must be provided to third party to preserve market integrity given that all LSEs will be transacting with each other
- True-ups can create significant rate volatility and limit the ability to accurately forecast total generation costs

Description of Other Alternatives (Buy-Out and Assignment)

Both options require a one-time calculation of the Net Present Value (NPV) of the historical generation portfolio (based on mutually agreeable long-term forecast of its market value)

NPV Calculation

- Reach agreement on forward energy prices to derive energy value (liquid markets available)
- Reach agreement on forward RA prices to derive RA Capacity value (no liquid markets)
- Reach agreement on forward renewables prices to derive renewables value (no liquid markets)
- Reach agreement on potential risk adjustments to account for uncertainty in market outcomes

Buy-Out

- LSE's buy-out amount would be equal to its pro-rata share of the historical portfolio NPV
- LSE's share of the utility portfolio will remain with the IOU

Contract Assignment

- Mutually-agreeable assignment of specific IOU contract(s) to the LSE; assigned contracts must have an NPV equal to the LSE's pro-rata share of the historical portfolio NPV
- Transfer of all rights and obligations from the IOU to the LSE
  - LSE assumes contract and resource management, as well as payment obligations, going forward
  - IOU, and its bundled service customers, would not have any further rights or obligations in those contracts for the period after the assignment, to the extent legally possible
- Requires approval from the contract's counterparty
- LSE's assumption of the IOU contract(s) relieves its customers of their cost responsibility for the remainder of the IOU's historical portfolio
- Must determine how to address special circumstances (e.g., unexpected terminations of either transferred or left-behind contracts)

Data-Based Comparison of Solutions

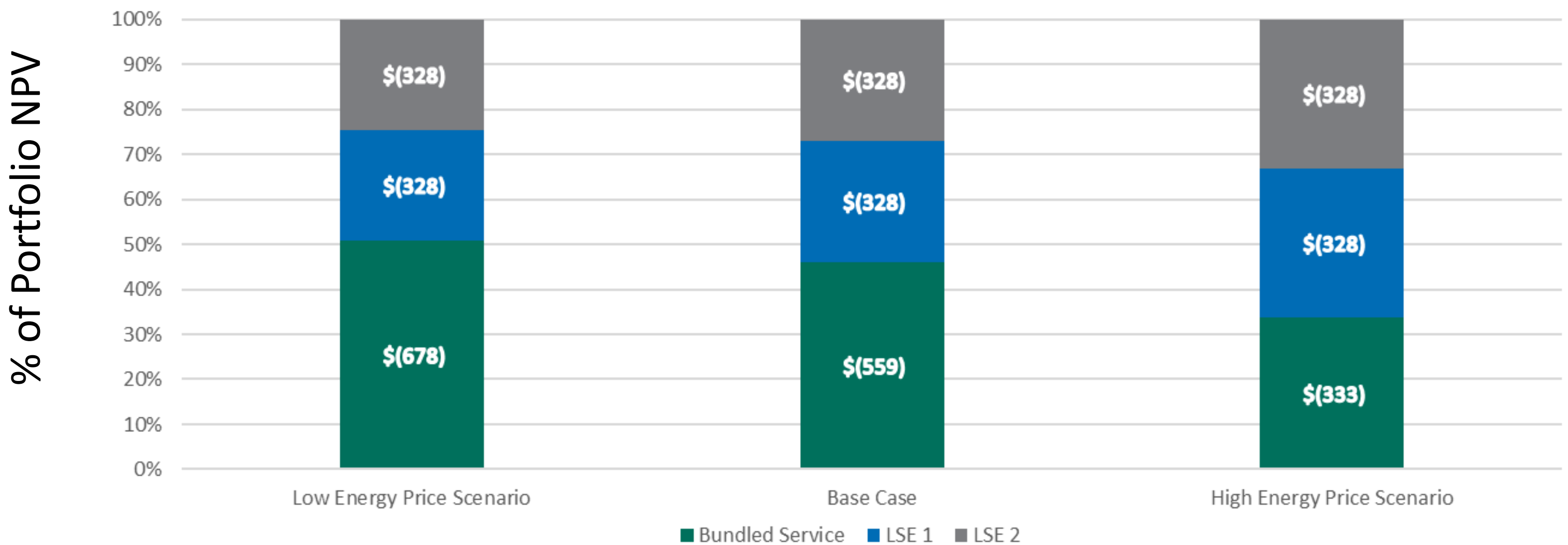
Ranbir Sekhon, SCE

Simplified Portfolio Assumptions

Resource	Capacity (MW)	Length	NPV - $M
RPS Contract 1	150	12	$ (251)
RPS Contract 2	150	12	$ (322)
RPS Contract 3	38	12	$ (77)
RPS Contract 4	20	12	$ (35)
RPS Contract 5	20	12	$ (35)
Gas Fired Toll 1	500	5	$ (85)
Gas Fired Toll 2	520	7	$ (131)
Gas Fired Toll 3	520	7	$ (131)
SRAC 1	38	12	$ (51)
SRAC 2	38	1	$ (2)
SRAC 3	37	6	$ (9)
SRAC 4	49.8	1.3	$ (4)
RA Only 1	238	3	$ (16)
RA Only 2	54	4	$ (2)
RA Only 3	250	8	$ (65)
Total			**$ (1,216)**

- Assume 3 LSEs – Determination of buy-out amount and/or contracts to be assigned is based on each LSE's share of the calculated portfolio NPV of $1,216M
  - IOU: 46% load share
  - LSE 1: 27% load share; $328M
  - LSE 2: 27% load share; $328M
- Actual market outcomes will differ from forecasts used to determine the initial NPV – must test each option's efficacy at various "scenarios"
  - 5th and 95th percentile scenarios reflect high and low scenarios for energy prices *only*
  - Flat price assumed for RPS and RA throughout analysis given lack of liquid/transparent markets
  - Portfolio NPV at the 5th Percentile energy price: $1,335M
  - Portfolio NPV at the 95th Percentile energy price: $990M
- Indifference for all customers is achieved when each LSE's share of the NPV is the same in all potential outcomes/scenarios

Model Results of Buy-Out Option



- LSE 1 and 2 make a one-time payment of $328M based on an initial NPV calculation using the base case energy price forecast[1]
- The LSE's "share" of the portfolio NPV changes based on actual market conditions
  - All customers indifferent if actual market conditions = base case assumed during NPV calculation
  - LSE 1 and 2 customers "win" in low-priced scenario
  - Bundled service customers "win" in high-priced scenario
- Because forecasts do not accurately predict future market prices, customer indifference is not achieved in a Buy-Out construct

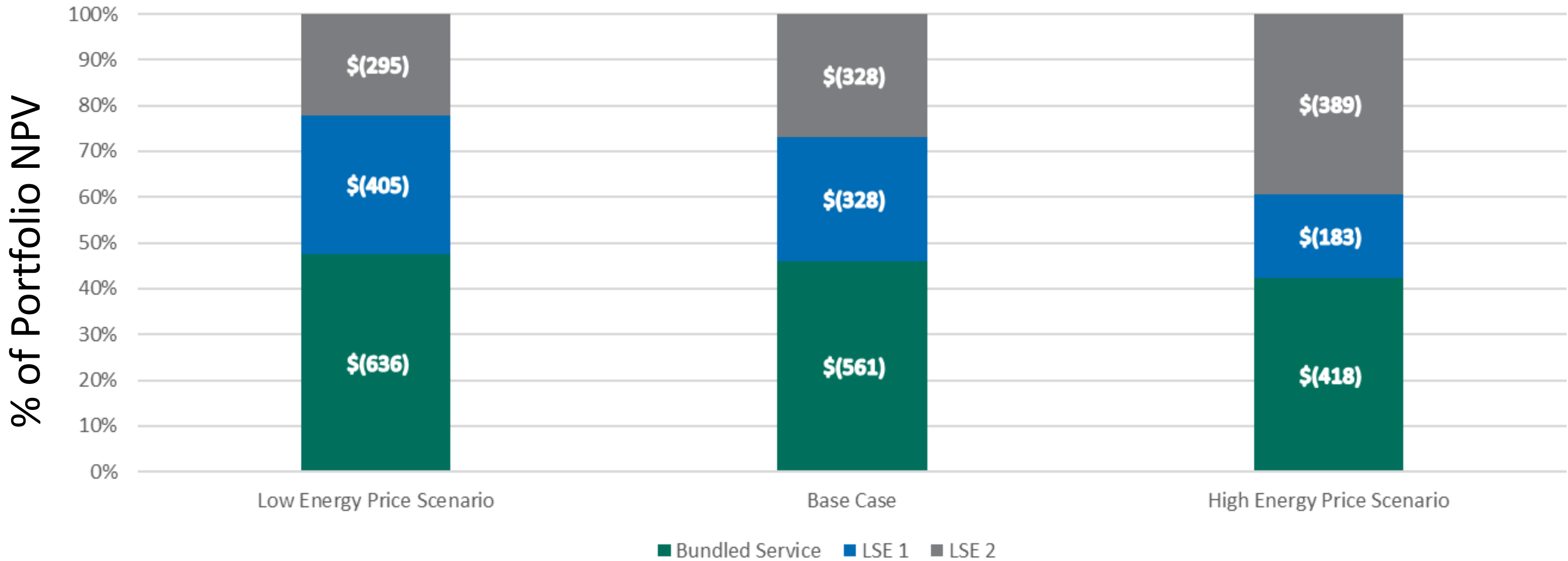
1 Renewables valued assuming a flat $10/MWh REC and RA valued at $25/kW-Year (shaped by month)

Model Results of Contract Assignment

Key	NPV (Base)
Bundled Service	$ (561)
LSE 1	$ (328)
LSE 2	$ (328)

Resource	NPV (Low)	NPV (Base)	NPV (High)
RPS Contract 1	$ (311)	$ (251)	$ (138)
RPS Contract 2	$ (382)	$ (322)	$ (209)
RPS Contract 3	$ (93)	$ (77)	$ (45)
RPS Contract 4	$ (43)	$ (35)	$ (21)
RPS Contract 5	$ (42)	$ (35)	$ (20)
Gas Fired Toll 1	$ (85)	$ (85)	$ (85)
Gas Fired Toll 2	$ (131)	$ (131)	$ (131)
Gas Fired Toll 3	$ (131)	$ (131)	$ (131)
SRAC 1	$ (25)	$ (51)	$ (100)
SRAC 2	$ (1)	$ (2)	$ (4)
SRAC 3	$ (4)	$ (9)	$ (17)
SRAC 4	$ (2)	$ (4)	$ (6)
RA Only 1	$ (16)	$ (16)	$ (16)
RA Only 2	$ (2)	$ (2)	$ (2)
RA Only 3	$ (65)	$ (65)	$ (65)
Total	$ (1,335)	$ (1,216)	$ (990)

Model Results of Contract Assignment

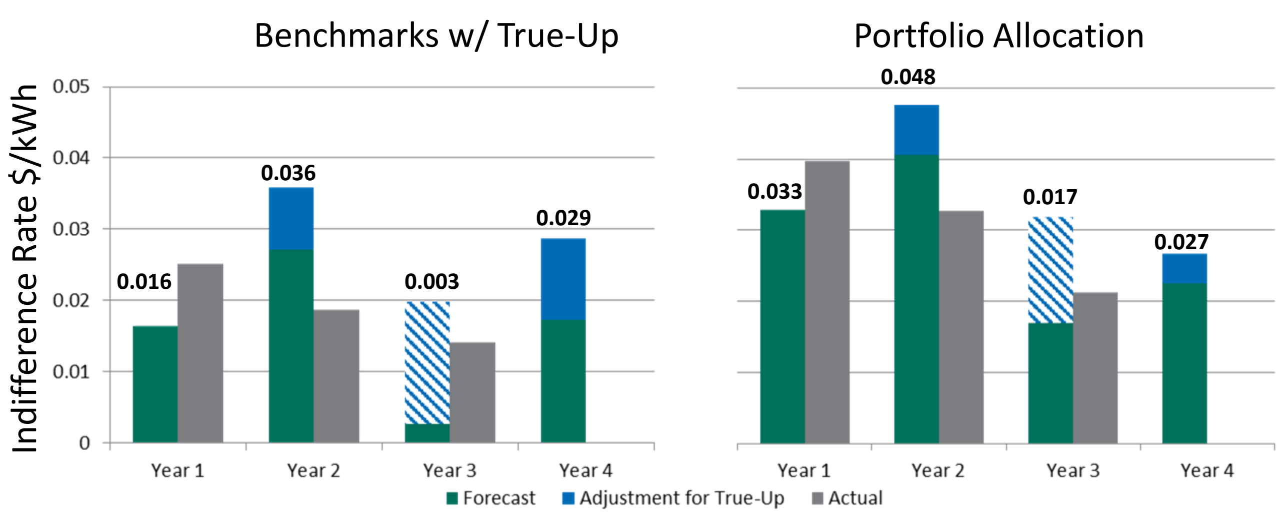


- Contracts assigned to LSE 1 have initial NPV of $328M (27.0%)
- Contracts assigned to LSE 2 have initial NPV of $328M (26.9%)[1]
- The LSE's "share" of the portfolio NPV changes based on how their assigned contracts fare during actual market conditions
  - All customers indifferent if actual market conditions = base case assumed during NPV calculation
  - LSE 2 customers "win" in varying degrees in low-priced scenario
  - Bundled service and LSE 1 "win" in varying degrees in high priced scenario

1 Allocated NPV between LSEs may not precisely match load share due to "lumpiness" of contract quantities, price and expiration

Comparison of Current Methodology with True-Up vs. Portfolio Allocation Methodology

- All vintaged over- or under-collections are shared by IOU and ESP/CCA customers
  - Portfolio Allocation Methodology requires annual true-up of actual portfolio costs and energy and ancillary services revenue
  - Benchmarks with True-Up requires additional true-up of REC and RA benchmarks (agreement on actuals – which could mean zero value)
- True-up of REC and RA benchmarks introduce additional volatility
  - Limited data sources available for use on a forecast basis
  - Significant variance between forecast and actual benchmark expected given depth of market concerns



Year	Forecast Conditions	Actual Conditions
Year 1	Base	Low
Year 2	Low	Base
Year 3	Base	High
Year 4	High	

PCIA Final Rate 0.003-0.036 (12x Max/Min Ratio) – PAM Final Rate 0.017-0.048 (3x Max/Min Ratio)

Matrix of Results (IOU Perspective)

Guiding Principle	Criteria	Current Method (No Update)	Buy-Out of Obligation	Contract Assignment	Benchmark Method with "True-Up"	Portfolio Allocation
Maintains customer indifference	At all price scenarios				☑ 1	☑
Transparent and Verifiable	All inputs and calculations are transparent and verifiable	☑ 2	☑	☑	☑ 2	☑
Reasonably Predictable Outcomes that Promote Certainty and Stability	Certainty on the costs and resulting rates		☑			☑
Scalable	At any level of load departure				☑ 1	☑
Does not create unreasonable obstacles for customers of non-IOU providers	Does not impede CCA expansion or formation	☑			☑	☑
Consistent with California energy policy goals and mandates	No "double procurement"			☑		☑

1 Requires agreement on process to true up RA and REC value without liquid or transparent markets
2 Market data used for benchmarks must be aggregated by a non-market participant third party

Matrix of Results

Guiding Principle	Criteria	Current Method (No Update)	Buy-Out of Obligation	Contract Assignment	Benchmark Method with "True-Up"	Portfolio Allocation
Maintains customer indifference						
Transparent and Verifiable						
Reasonably Predictable Outcomes that Promote Certainty and Stability						
Scalable						
Does not create unreasonable obstacles for customers of non-IOU providers						
Consistent with California energy policy goals and mandates						

Appendix

Formulas with Net Short costs included

- $R_1 = \dfrac{C_P + (NS \times P_1)}{kWh_B + kWh_{DL}}$
  - **Added Net Short position** (NS) **x Price Paid by the IOU to fill it** (P_1)
- $IR = \dfrac{C_P - (MPB \times G_P)}{kWh_B + kWh_{DL}} = \dfrac{C_P}{kWh_B + kWh_{DL}} - \dfrac{(MPB \times G_P)}{kWh_B + kWh_{DL}}$
  - **Net short costs are not included in the Indifference Rate Calculation**
- $R_2 = \dfrac{C_P + (NS \times P_1) - (Pact \times \dfrac{kWh_{DL} \times GP}{kWh_B + kWh_{DL}}) - (IR \times kWh_{DL})}{kWh_B}$
  - **Bundled Service Rate After Departure:** (PCIA-eligible Portfolio Cost + cost of filling the Net Short position – Revenues received by IOU for the sale of the Departing Load customers' share of PCIA-eligible Portfolio – PCIA and CTC paid by Departing Load customers) ÷ Remaining Bundled Service Load
- $R_2 - R_1 = \dfrac{kWh_{DL}}{kWh_B} \times \dfrac{G_P}{kWh_B + kWh_{DL}} \times [MPB - P_{act} + (P_1 \times \dfrac{NS}{G_P})]$