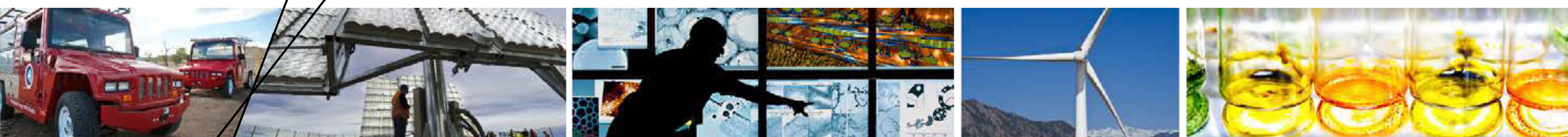
California-specific Power-to-hydrogen and Power-to-gas Business Case Evaluation



Final presentation of results

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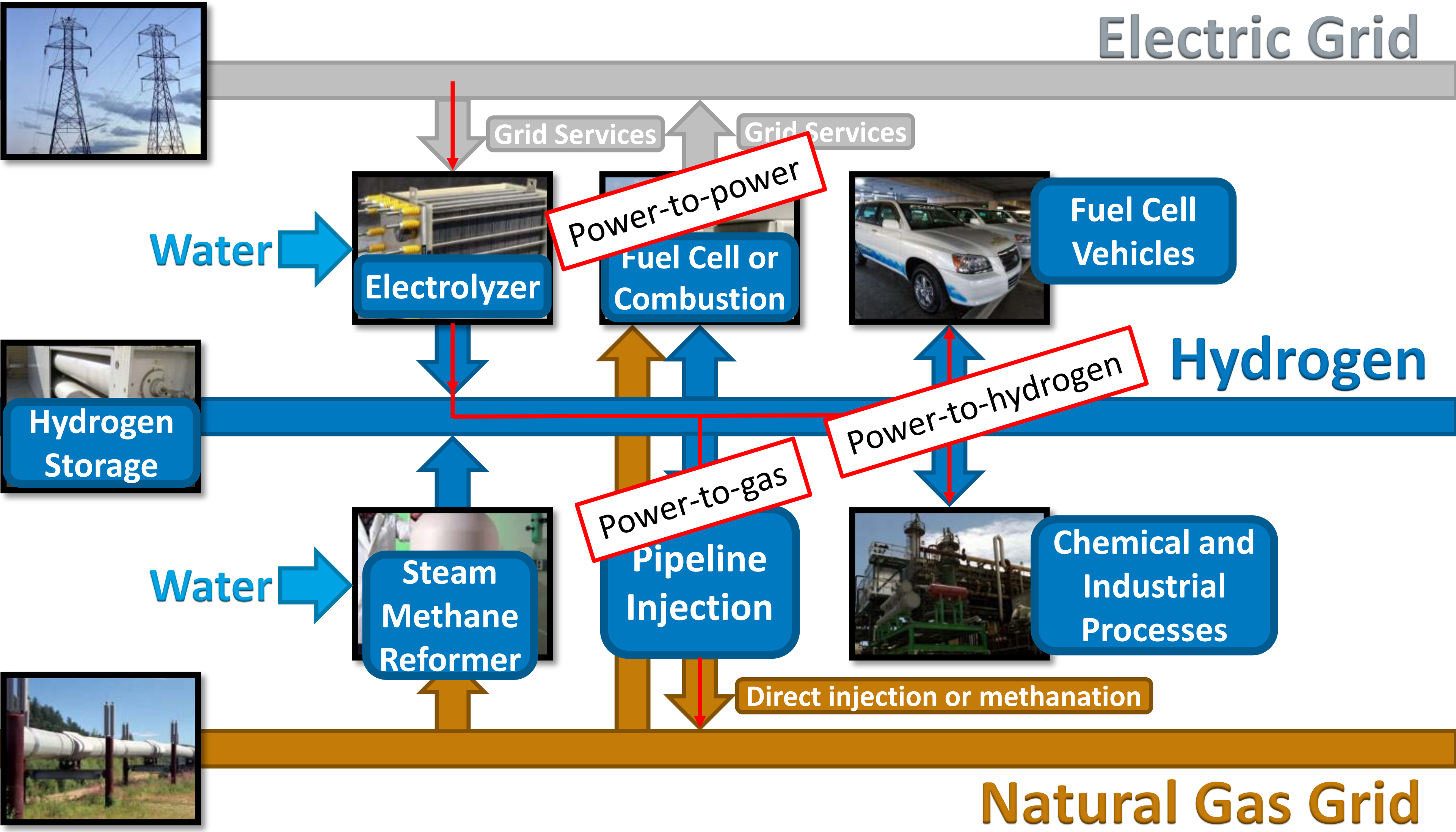
Overview

- **Goal**
  - "Assess the <u>business case</u> of power-to-gas (and power-to-hydrogen) systems for <u>near-term</u> applications in <u>specific locations</u> in California"
- **Review Scenarios**
- **Methodology and assumptions**
- **Results**

Hydrogen System Configurations



Source: (from top left by row), Warren Gretz, NREL 10926; Matt Stiveson, NREL 12508; Keith Wipke, NREL 17319; Dennis Schroeder, NREL 22794; NextEnergy Center, NREL 16129; Warren Gretz, NREL 09830; David Parsons, NREL 05050; and Bruce Green, NREL 09408

Scenarios

#	End-Use	Delivery	Renewable Source
1	Transportation fuel	Truck – compressed gas	Wind or PV
2		Hydrogen Pipeline	Wind or PV
3	Industrial gas – Petroleum refinery	Hydrogen Pipeline	Wind or PV
4	Injection into natural gas pipeline	-	Wind or PV

- **Multiple potential value streams considered**
  - Utility tariffs
    - Demand-side energy management (demand and energy charges)
  - Utility DR programs
    - Can receive credit from reducing demand several times per year
  - California electricity market participation
    - Programs exist that allow for DR participation in markets
    - Can reduce operating cost and increase revenues
    - Location has a significant impact on electricity price

Parameter space for analysis

- **The model is run for every combination of parameters below**
- **Also each utility rate and each voltage connection level are considered**

Hydrogen Production Technology	Operation Strategy	Installed Capacity	Yearly Capacity Factor	Storage Duration	Installed Renewables
Electrolyzer	Baseload	0.42, 0.63, 0.84, 0.95, 1 MW	95%	-	0 – 4 MW
	Flexible	1 MW	40%, 60%, 80%, 90%, 95%	1 to 168 hours 18.4 to 3,094 kg	0 – 4 MW
	Flexible +Nonspinning Reserve	1 MW	40%, 60%, 80%, 90%, 95%	1 to 168 hours 18.4 to 3,094 kg	0 – 4 MW
	Flexible+Spinning Reserve	1 MW	40%, 60%, 80%, 90%, 95%	1 to 168 hours 18.4 to 3,094 kg	0 – 4 MW
	Flexible+Regulation Reserve	1 MW	40%, 60%, 80%, 90%, 95%	1 to 168 hours 18.4 to 3,094 kg	0 – 4 MW
Steam Methane Reformer	Baseload	177, 265, 354, 398, 420 kg/day	100%	-	0 MW

Equipment Cost Assumptions

Properties	Electrolyzer	Steam Methane Reformer	PV	Wind
Rated Power Capacity (MW)	0.42 – 1.0	177 – 420 kg/day	0.0 – 4.0	0.0 – 4.0
Energy Capacity	4 hours 74 kg H_2	4 hours 74 kg H_2	-	-
Capital and Installation Cost ($/kW)	1,414 [a]	1,092 $/kg/day [a]	2,540 [b]	1,711 [c]
Fixed O&M ($/kW-year)	69.7 + 25.0 (stack replacement) [a]	4.5% of Capital [a]	0 [b]	50 [c]
Lifetime (years)	20	20 [a]	20	20
Interest rate on debt	7%	7%	7%	7%
Efficiency	61.4% LHV [a] (54.3 kWh/kg)	0.156 MMBTU/kg [a] 0.6 kWh/kg [a]	-	-
Minimum Part-load	10%	-	-	-

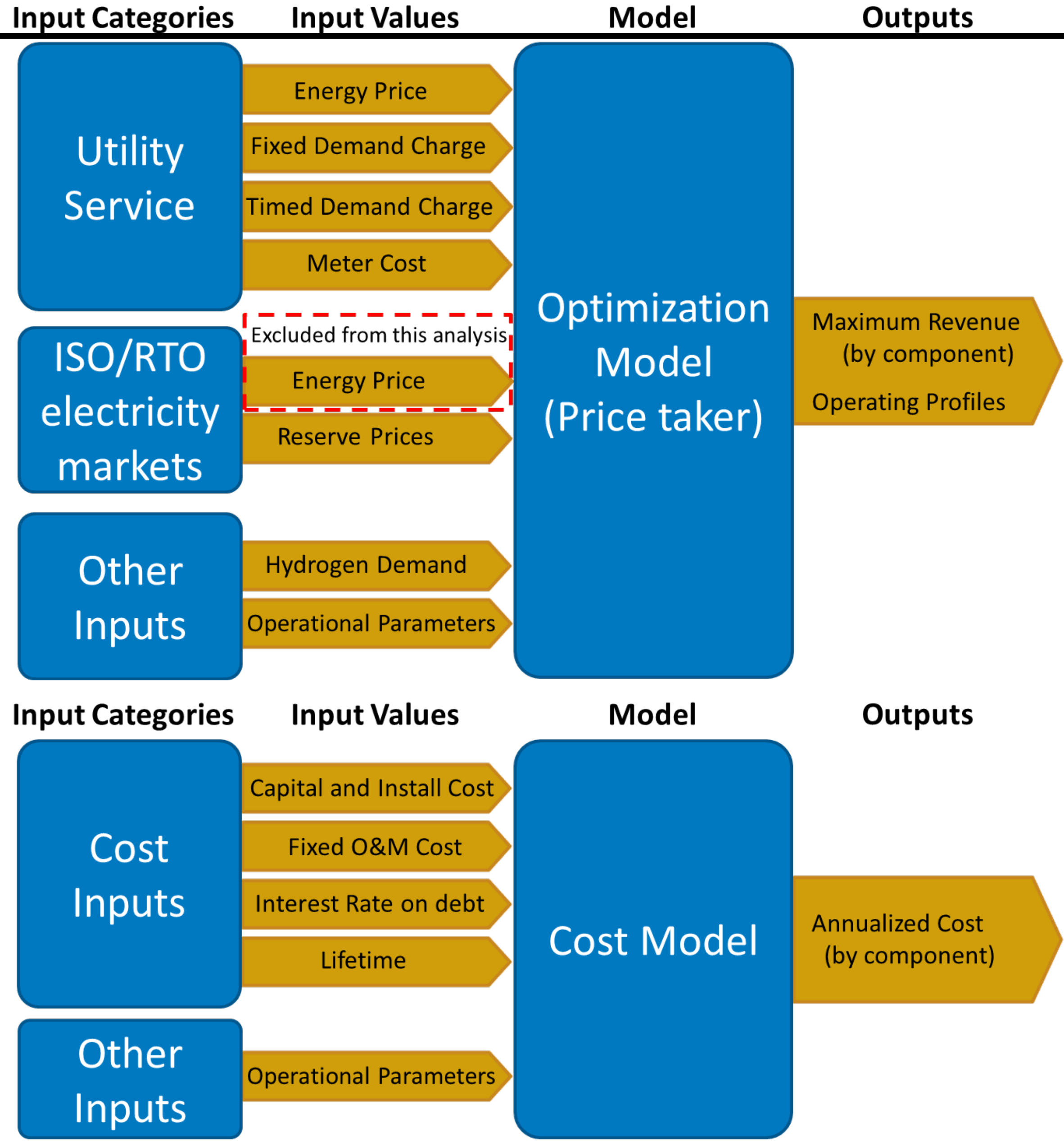
Source: [a] NREL - H2A Model version 3.0
[b] DOE - Photovoltaic System Pricing Trends, 2014
[c] NREL - Annual Technology Baseline, 2015

Electricity and gas data

- Electricity tariff sheets, 2015 (PG&E E20, SCE TOU8, SDGE ALTOU + EECC-CPP-D)
- Demand response programs, 2015 (BIP, CBP, DBP, CPP/PDP)
- Natural gas tariff sheets, 2015 (PG&E GNR2, SCE & SDGE GN-3)
- California renewable generation, 2015 (CAISO Renewable Watch)
- CAISO nodal electricity data, 2015 (Ventyx)
- CAISO Ancillary Service prices, 2015 (CAISO OASIS)
- Hydrogen compression storage and delivery costs (Hydrogen Delivery Scenario Analysis Model (HDSAM))

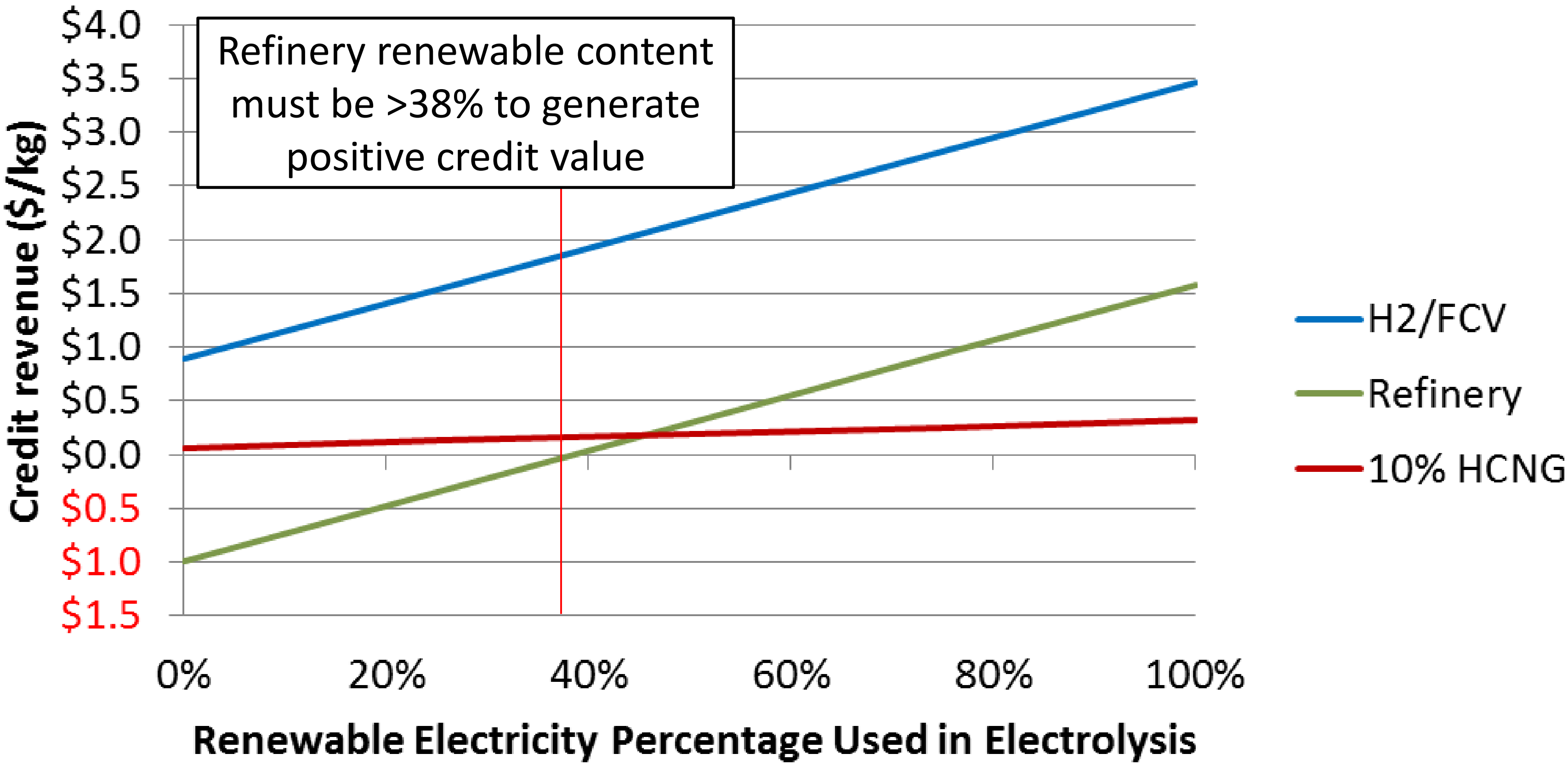
Methodology

- **Optimization model performs time-resolved co-optimization of energy, demand charges, hydrogen sale and ancillary services**
- **Assumptions**
  - Sufficient capacity is available in all markets
  - Objects don't impact market outcome (i.e., small compared to market size, and early market)



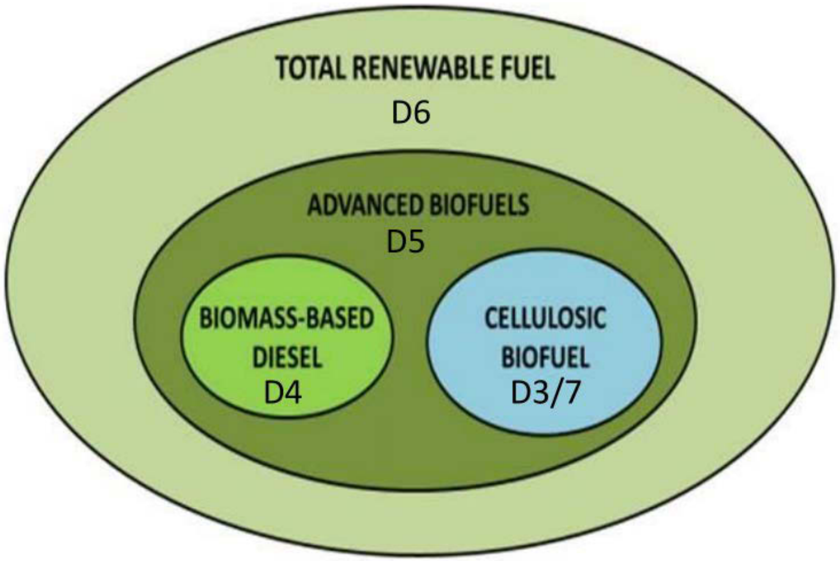
Low Carbon Fuel Standard

- **Annual Revenues from LCFS Credits @ $125/credit**
  - 1 MW electrolysis plant
  - 54.3 kWh/kg (61% efficiency, LHV)



Renewable Fuel Standard

- **Does not currently recognize power to gas**
  - Suggestion: including hydrogen through electrolysis in RFS
  - Potential categories: D6, D5
  - Hydrogen pathways that use biogas can collect “cellulosic” D3 RINs.
- **“Electrolyzed” hydrogen would get 1.5 RINs per kg**
  - 1 kg of H2 has roughly 1.5 times the energy content in 1 gallon of ethanol
  - Using Sep/Oct 2015 D6, D5 prices: \$0.44, \$0.57/kg respectively



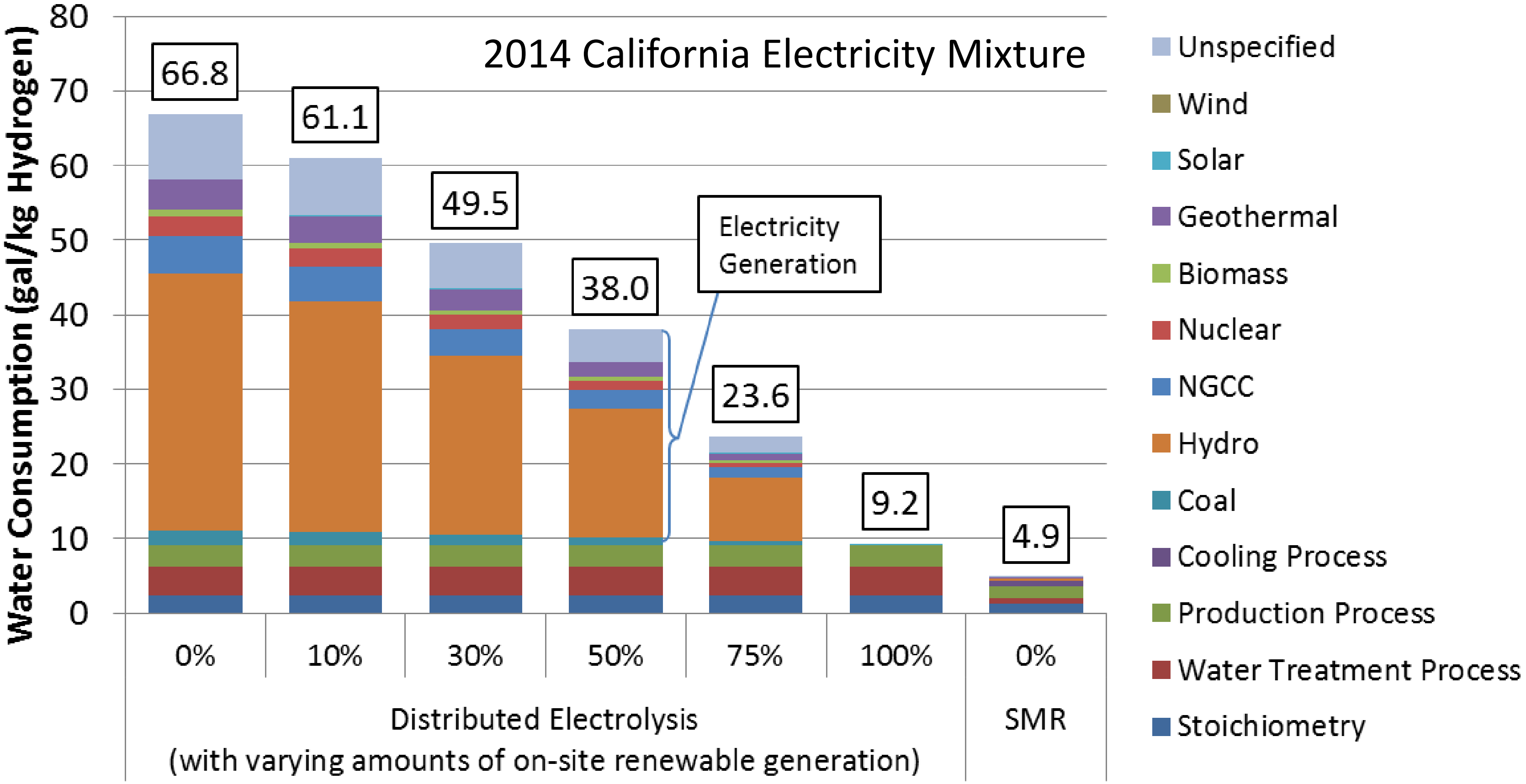
Category	RIN Code	Characteristics	Mandated volume 2016 (million gallons)
Renewable fuel	D6	> 20% GHG reduction	14,000
Advanced biofuels	D5	> 50% GHG reduction	3,400
Biomass-derived diesel	D4	Biodiesel, renewable diesel, etc.	1,800
Cellulosic biofuel	D3/D7	> 60% GHG reduction	206

Results

- **Water consumption**
- **Summary of scenario results**
  1. Hydrogen for FCEVs, truck delivery
     - High FCEV market value and conventional delivery
     - Low demand for FCEVs
  2. Hydrogen for FCEVs, pipeline delivery
     - High FCEV market value and potentially lower cost delivery.
     - Low demand for FCEVs
  3. Hydrogen for refinery, pipeline delivery
     - Large demand for refineries and can take advantage of existing compression and pipeline equipment
     - Low LCFS credit
  4. Hydrogen for HCEVs, inject into natural gas pipeline
     - Large demand in natural gas pipeline
     - Could adjust heating content of natural gas system
     - Low value for heating fuel and low LCFS value for HCEVs
- **Additional findings (sensitivities)**
- **Locational Impacts**
- **Future impacts**

Water use for hydrogen production

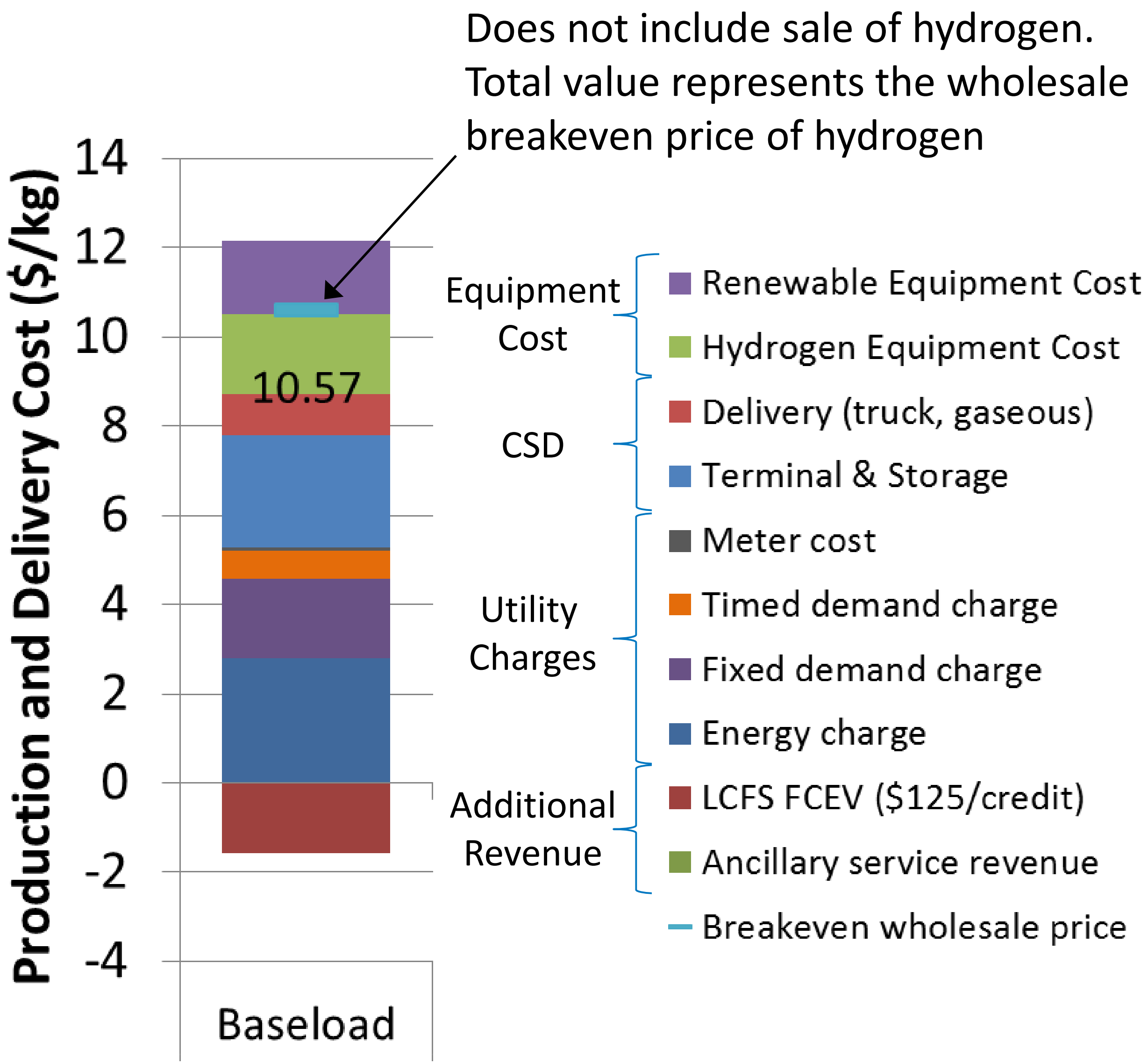
- **Water consumption based on the 2015 Argonne Study and adjusted for California.**



Based on Elgowainy, A., et al., http://www.hydrogen.energy.gov/pdfs/review15/sa039_elgowainy_2015_o.pdf

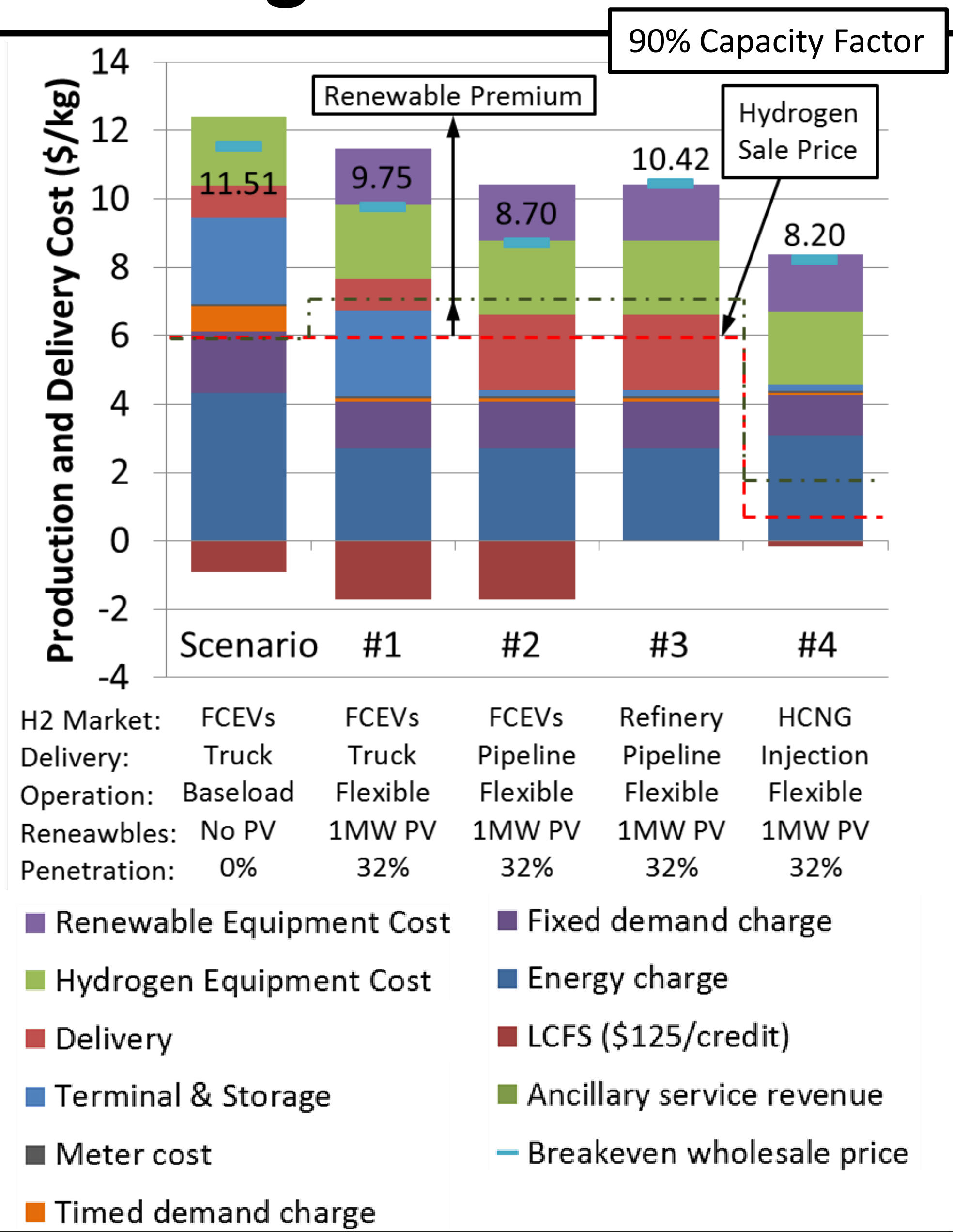
Example cost/benefit figure

- **Combines revenues and cost values**



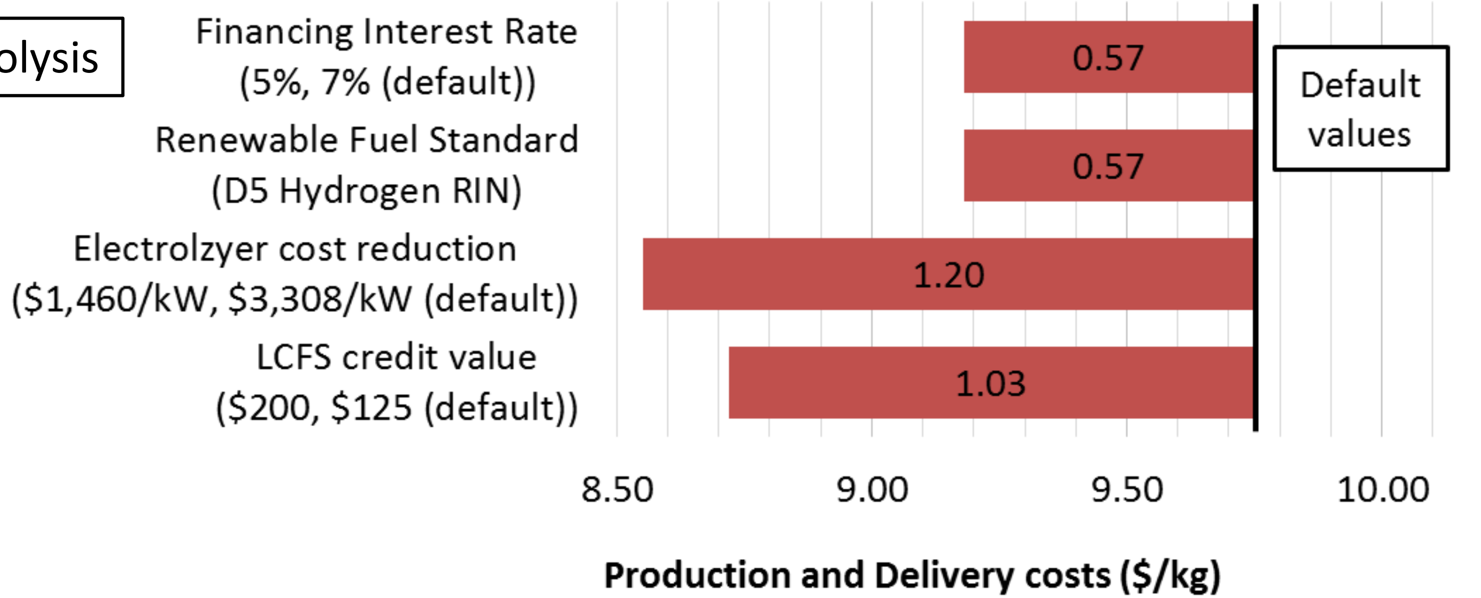
Summary of scenario findings

- The addition of on-site renewables reduces all energy cost components and is even valuable without the LCFS.
- Scenario 1 and 2 are the most compelling because of the LCFS for FCEVs.
- Pipeline delivery is cheaper but can vary significantly based on location compared to truck delivery.

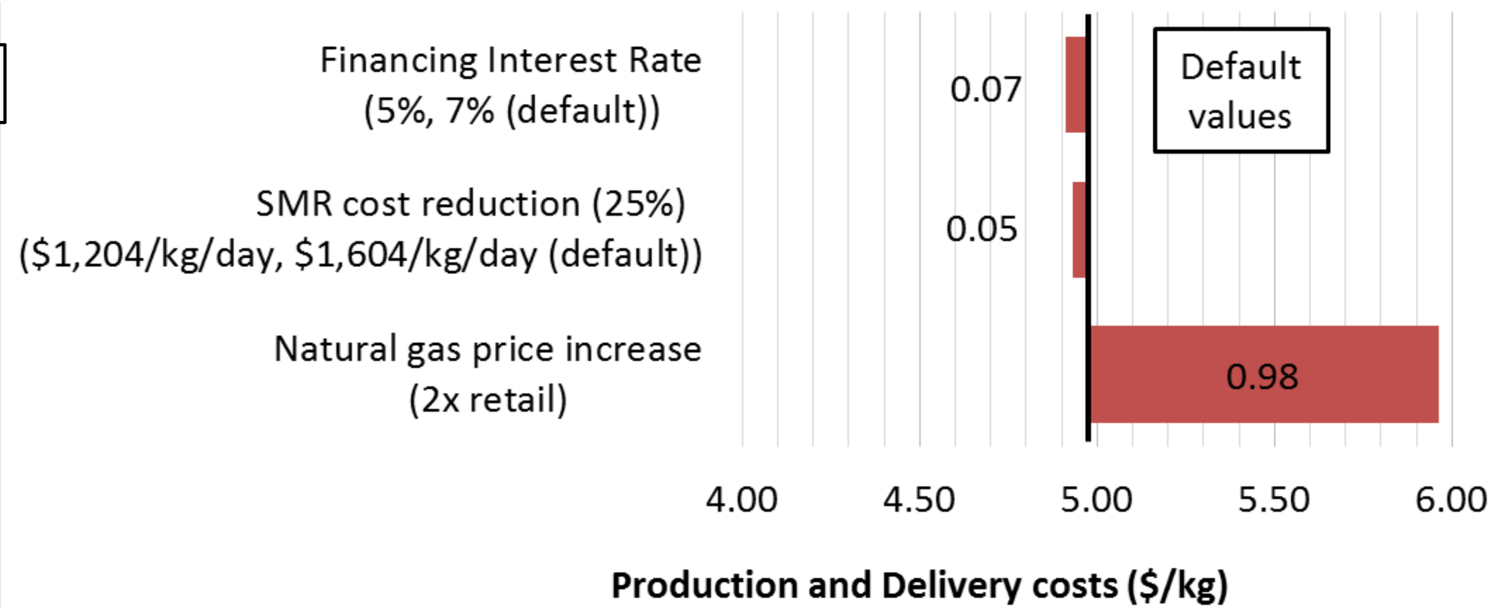


Considerations for future impacts

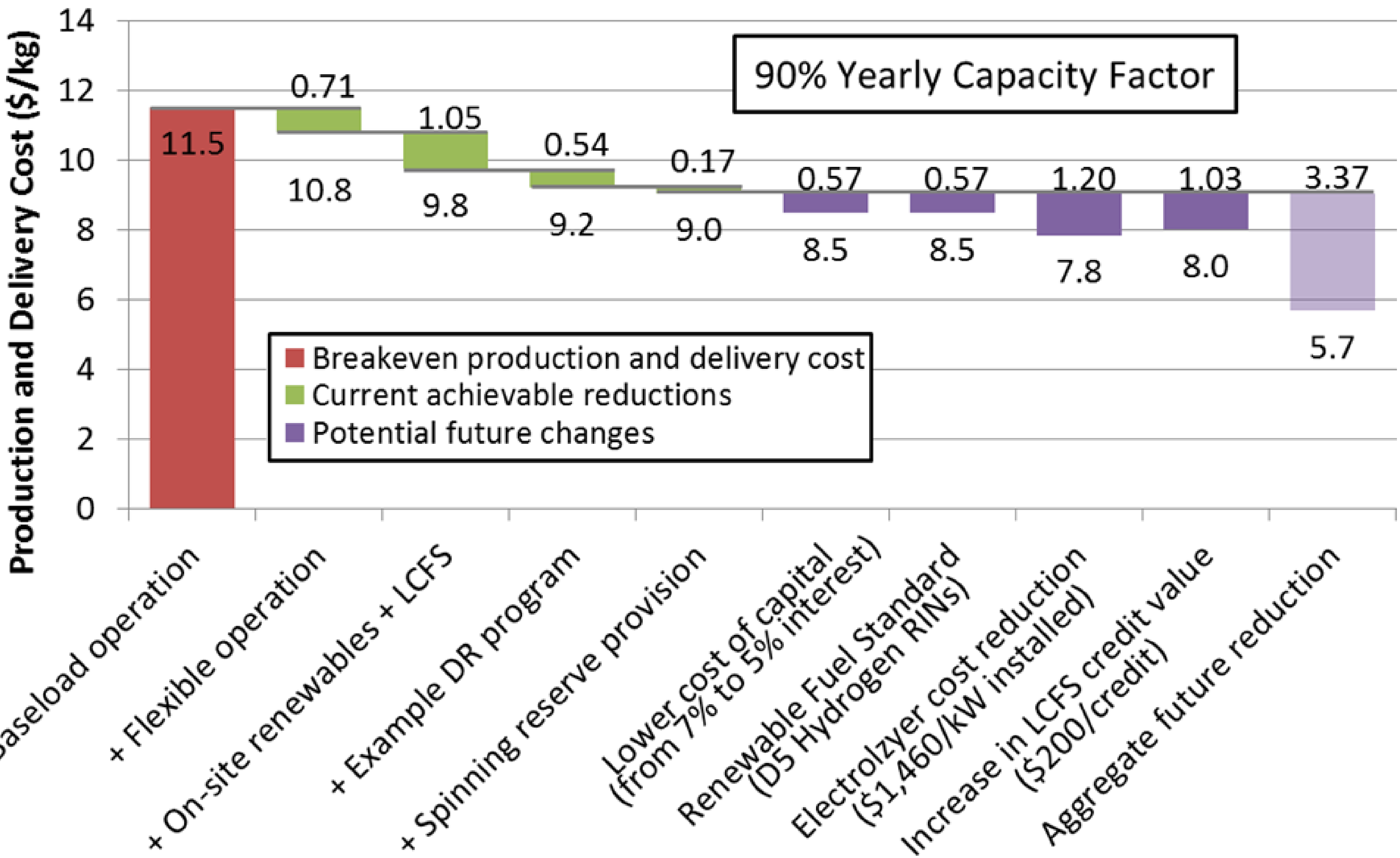
Impact on Electrolysis



Impact on SMR

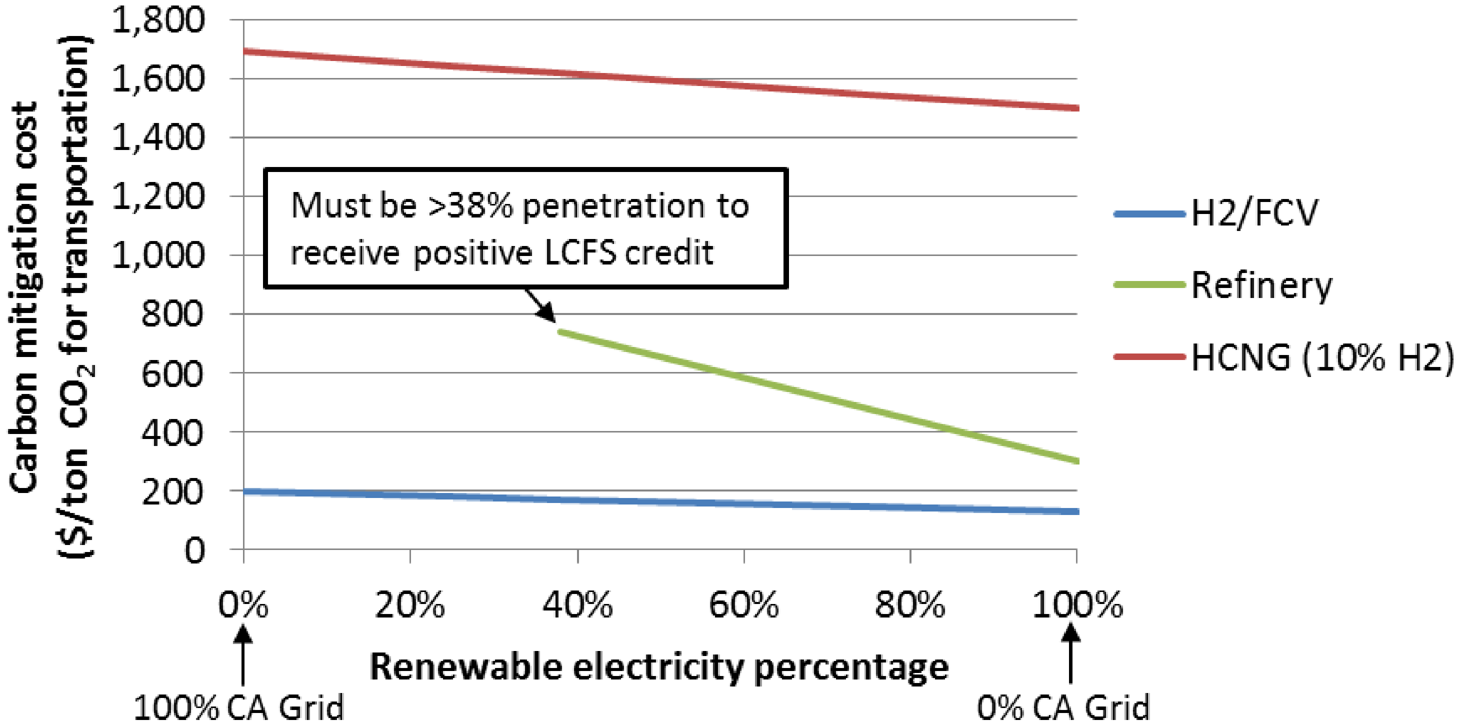


Summary (Scenario 1, FCEV w/ truck delivery)



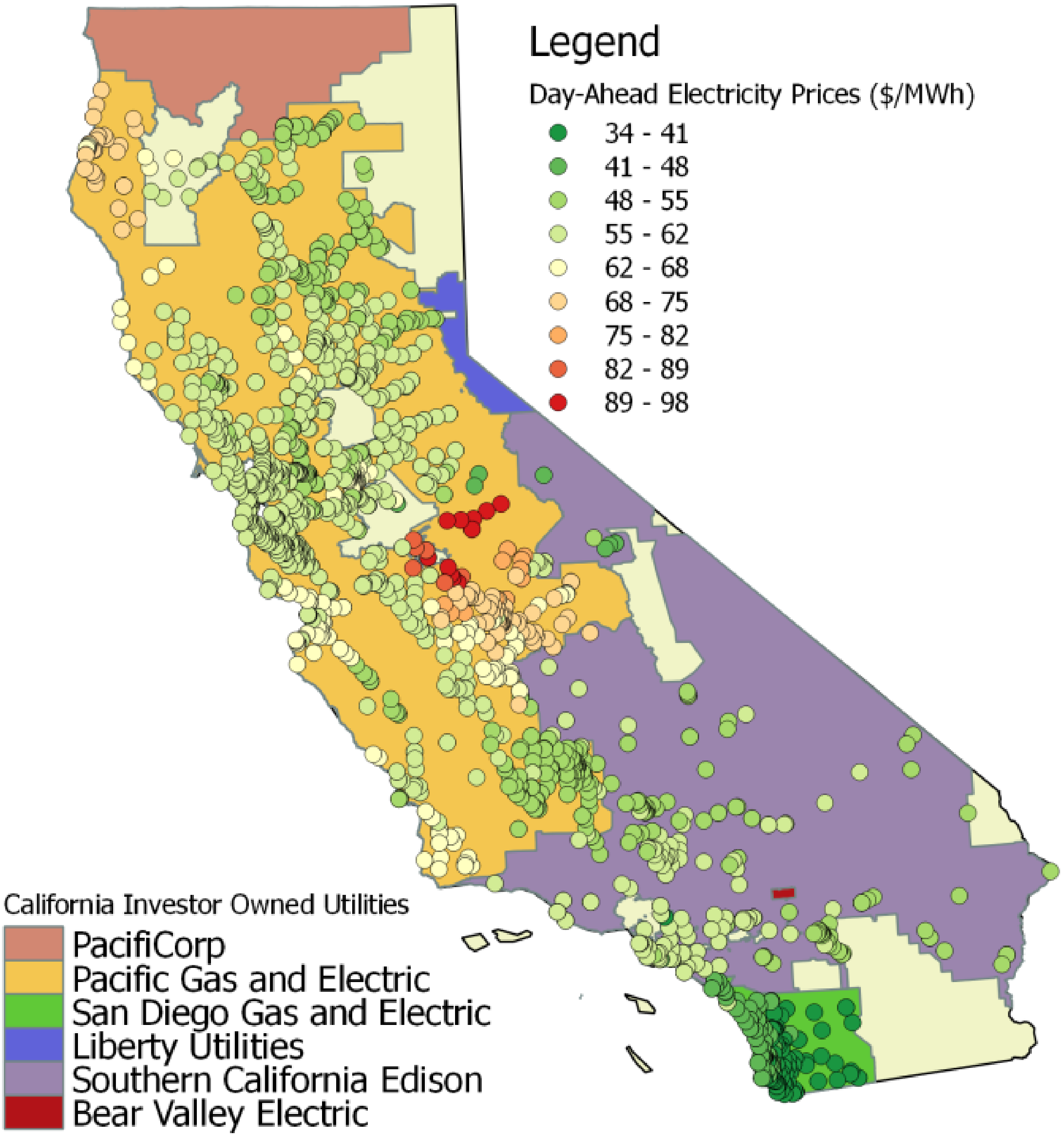
Carbon Mitigation Cost

- Represents "Capital and FOM cost" / "carbon reduction"
- As penetration increases carbon reduction increases along with renewable system costs
- Additional benefits are provided to the grid from greater flexibility (e.g., system efficiency and carbon emissions)



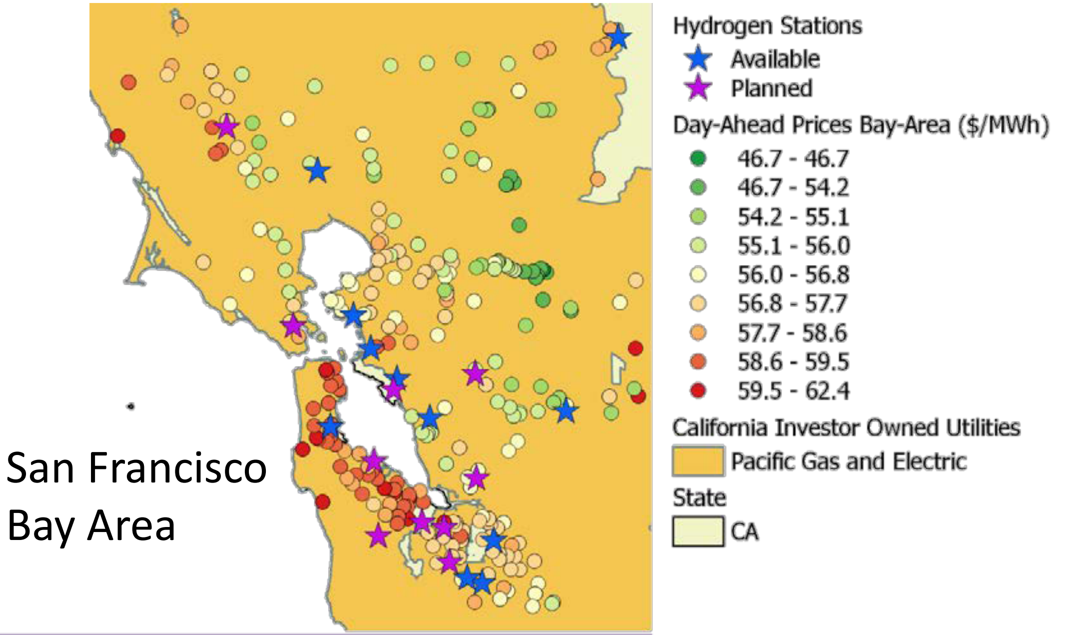
Value for ISO market participation

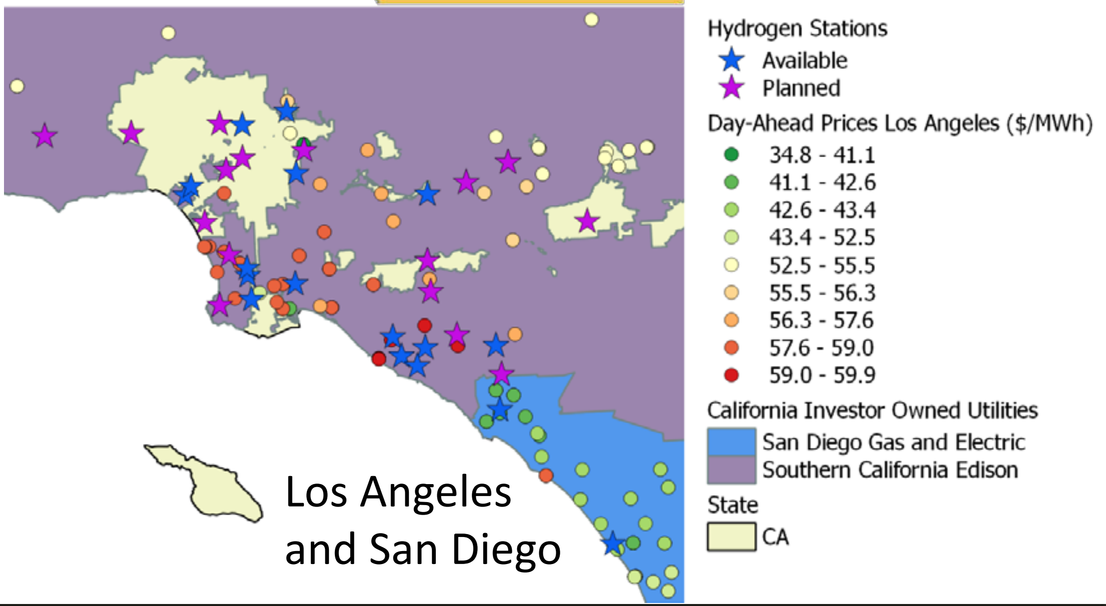
- **ISO energy prices vary by location, market and time**
- **Energy markets can reduce cost but market prices must be greater than retail rates to encourage DR to participate**
- **Presently, ancillary service market participation for demand response only allows for non-spinning reserve and spinning reserve (i.e., PDR)**



Locational Analysis

- **Currently, energy market value comes from reducing demand during price spikes**
- **Areas with high average energy prices are good candidates to capitalize on price spikes**





Summary

Utility	Utility Rates	Ancillary Service Value	Average Energy Price
SCE	Low	High	High
PG&E	Medium	Low	High
SDGE	High	High	Low

Recommendations for specific groups

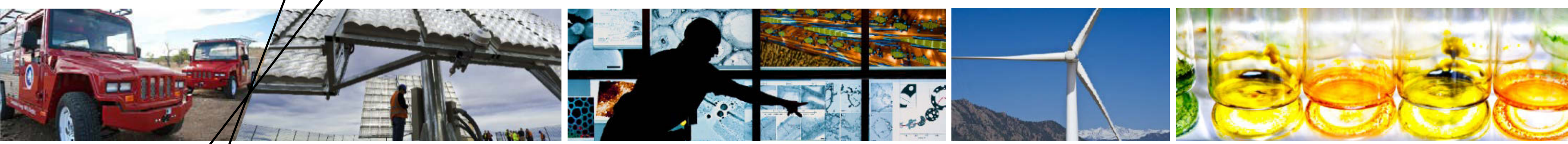
- **Continue activities to lower barriers to DR participation in electricity markets, and address baseline (10-in-10) and daily use for highly flexible resources (CPUC, CAISO)**
- **Dedicated electricity rate for electrolyzers (use PEV rates as model) (CPUC, utilities)**
- **Continue to evolve carbon credit markets (e.g., refinery pathway) (ARB)**
- **Encourage technology advancement and demonstrations (when appropriate) to prove value for electrolysis (CEC, DOE)**

Summary of additional findings (1)

- **Findings**
  - On-site renewables provide a demand charge and energy cost reduction in addition to the LCFS. However co-location with a larger load should be considered with on-site renewables to achieve higher renewable penetrations (>30%).
  - Lowering annual hydrogen production (capacity factor) reduces hydrogen revenue but also reduces electricity cost. Given the current utility rates, 90% is the preferred capacity factor.
  - Greater storage must balance electricity cost reductions versus additional storage costs. 4-8 hours of storage capacity is sufficient to provide constant supply of hydrogen.
  - There are opportunities for further reductions with new or more aggressive rate structures (e.g., EV charging rates, real-time pricing).
  - Could benefit from harmonization of utility rates and ISO markets. One area to target is compensation for increasing load and the baseline methodology for DR.

Summary of additional findings (2)

- **Findings**
  - Ancillary services can add 1 ¢/kg (non-spinning), 17 ¢/kg (spinning) and 28 ¢/kg (regulation up and down) at 90% capacity factor. This value must be sufficient to pay for connection to the ISO (e.g., meter with telemetry)
  - Excess generation can improve economics if you are in the right location to benefit; however, the number of hours limits the benefit. Also, once there is a sink for electrons they will increase in value.
  - Islanded installations must purchase additional storage to capture entire renewable resource. Additionally, low capacity factor from renewables can contribute to significant costs for stranded electrolyzer assets
  - Purchasing biogas would be a cheaper option for increasing renewables to receive the LCFS (although potentially not allowed). Purchasing biogas credits would cost 8-80 ¢/kg for 100% renewable and sell for up to \$3.5/kg in FCEV markets.



Backup

Properties and sensitivities

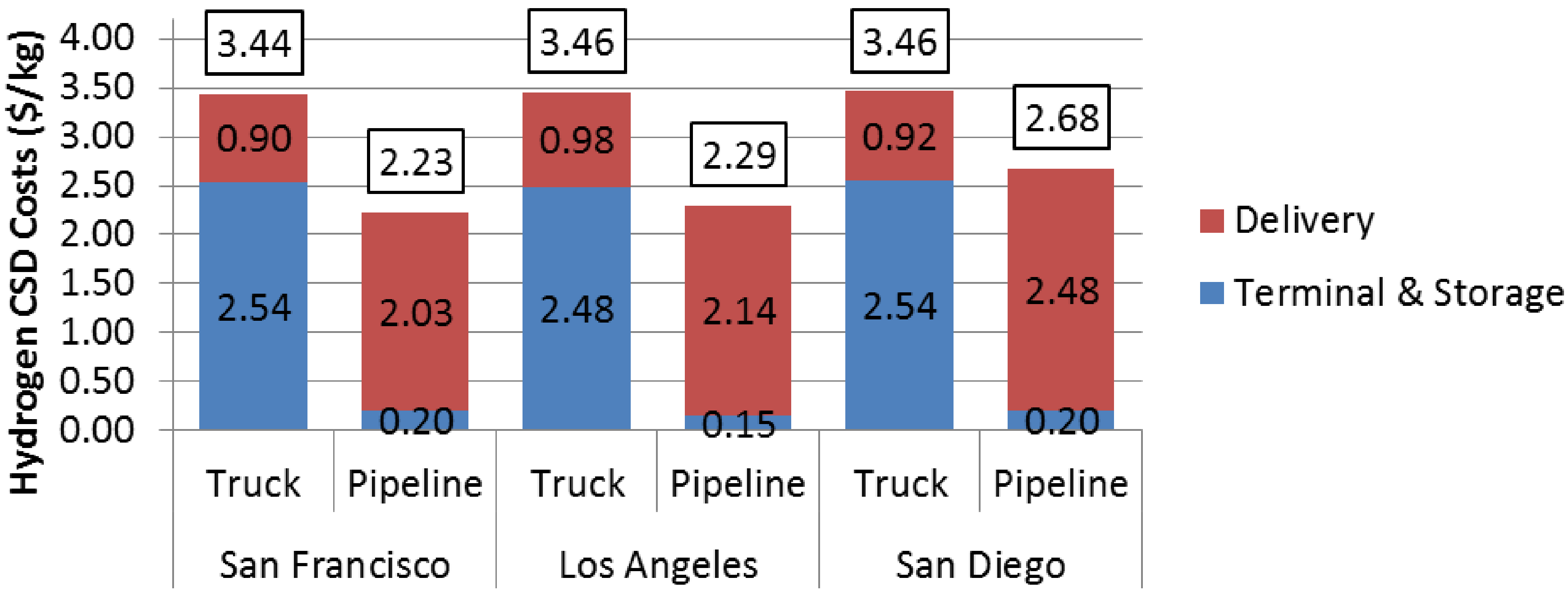
- **Considered sensitivities for each item below (baseline = underlined)**

Utility Area	Connection	Utility Rate	Capacity	Renewable limits
PG&E	Secondary (<2.4kV) Primary Transmission	E20	≥1,000kW	
		E20R	≥1,000kW	≥15%
SCE	Secondary (≤2kV) Primary (2-50KV) Transmission (>50kV)	TOU8B	≥500kW	
		TOU8R	≥500kW	≥15%
SDG&E	Secondary Primary Transmission	ALTOU + EECC-CPP-D	≥500kW and <12MW	
		DGR + EECC-CPP-D	≥500kW and <2MW	≥10%

Utility Area	Utility Rate	Description
PG&E	GNR2	Large commercial customers (2015)
SCE and SDG&E	GN-3	Core non-residential customers (2015)

Storage and delivery assumptions

- **Values are calculated using the Hydrogen Delivery Scenario Analysis Model (HDSAM)**
- **Assuming a combined urban and rural hydrogen market with <u>5% market penetration</u> and low volume production**



DR program assumptions

Demand Response Program	Description	Value
Base Interruptible Program (BIP)	Event based demand reduction program. There is a penalty charged if the device does not respond as prescribed during an event.	PG&E: $8-9/kW/month SCE: $1.12 to 23.17/kW/month SDGE: $2 (winter) or $12/kW/month (summer)
Capacity Bidding Program (CBP)	Event based demand reduction program. There is a penalty for not achieving the specified capacity reduction.	PG&E: $3.04 to $24.81/kW/month SCE: $1.13 to $22.46/kW/month SDGE: $2.43 to $28.65/kW/month
Demand Bidding Program (DBP)	Event based demand reduction program. There is no penalty for not providing a reduction during an event.	PG&E: $500/MWh SCE: $500/MWh SDGE: $500/MWh
Critical Peak Pricing (CPP) or Peak Day Pricing (PDP)	Lower energy prices or demand charges throughout the year during non-event hours but a high cost during event hours.	PG&E: $1.19 to $6.50/kW/mth for E20 SCE: Reduction varies SDGE: $0.3/MWh reduction (AL-TOU)

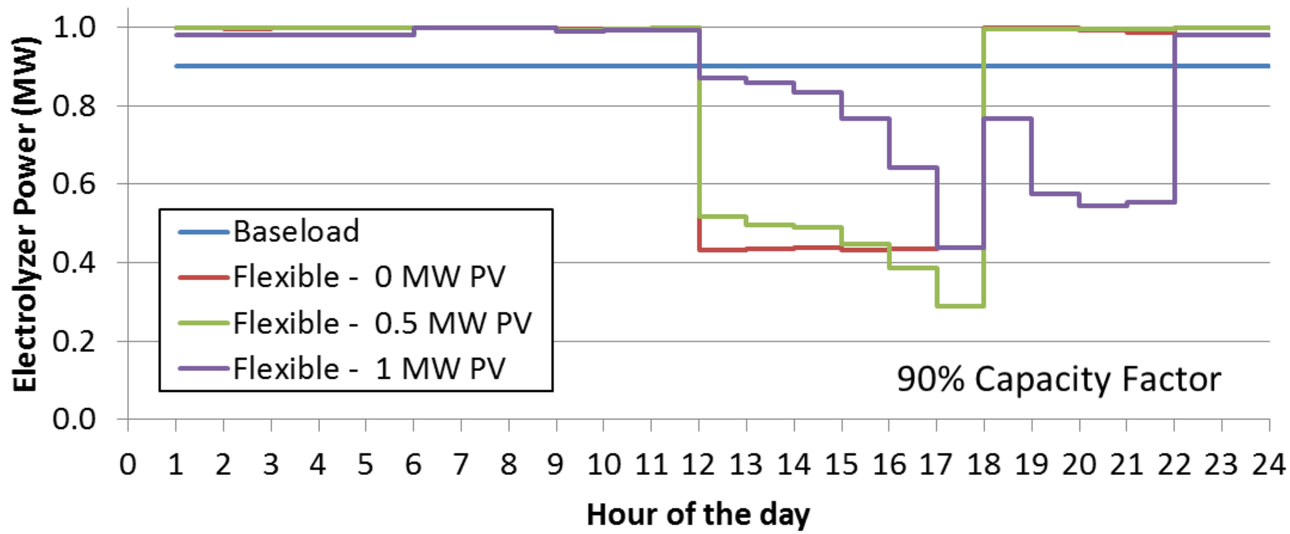
SCE DR Event History

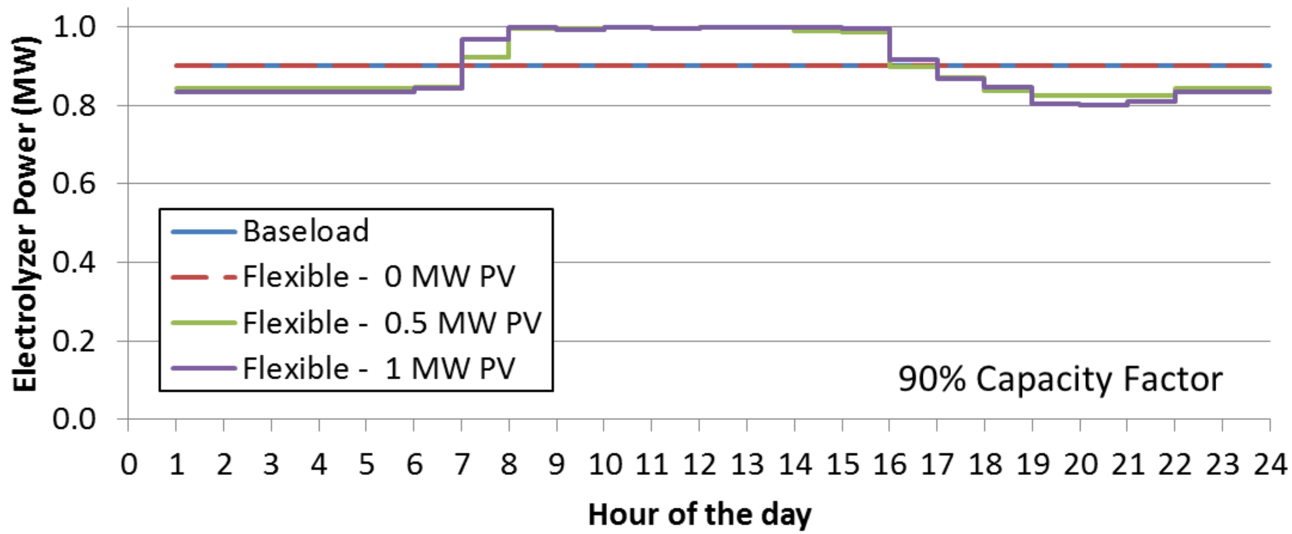
Program	Product	2011	2012	2013	2014	2015
BIP	BIP	1	1	1	1	1
CBP	CBP 1-4 hour Day-ahead	19	12	28	26	63
	CBP 2-6 hour Day-ahead	10		22	11	25
	CBP 4-8 hour Day-ahead			10		
CPP	Residential & Commercial	12	12	12	12	12
DBP	DBP Day-ahead	6	8	5	6	10

Data from SCE demand response event history website (https://www.sce.openadr.com/dr.website/scepr-event-history.jsf)

Electrolyzer operation

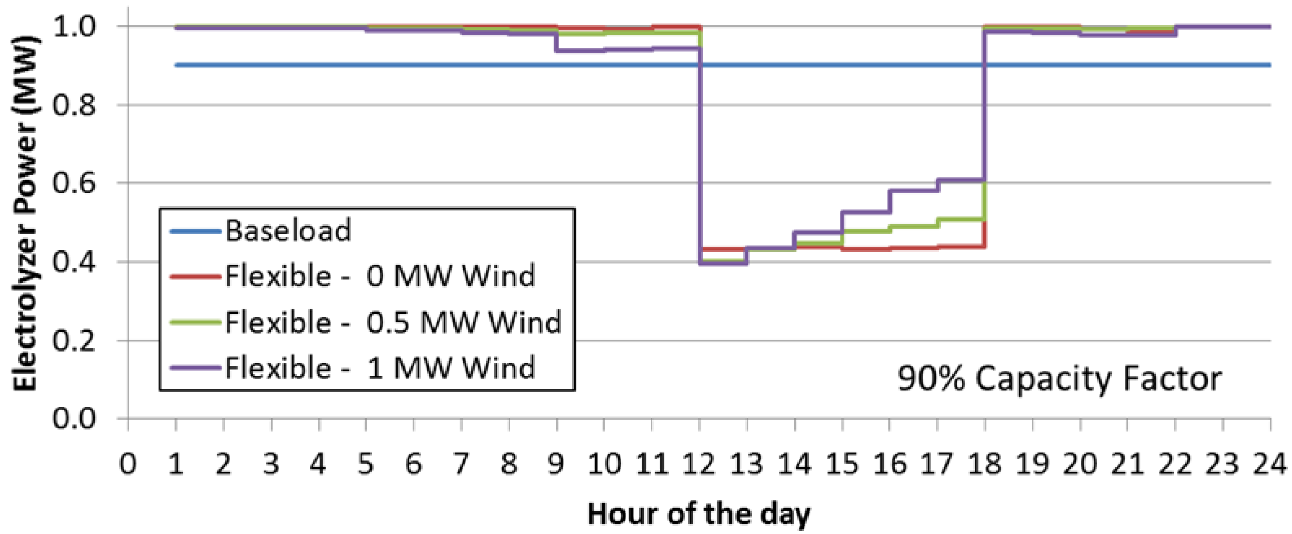
- **Optimized operation profiles**

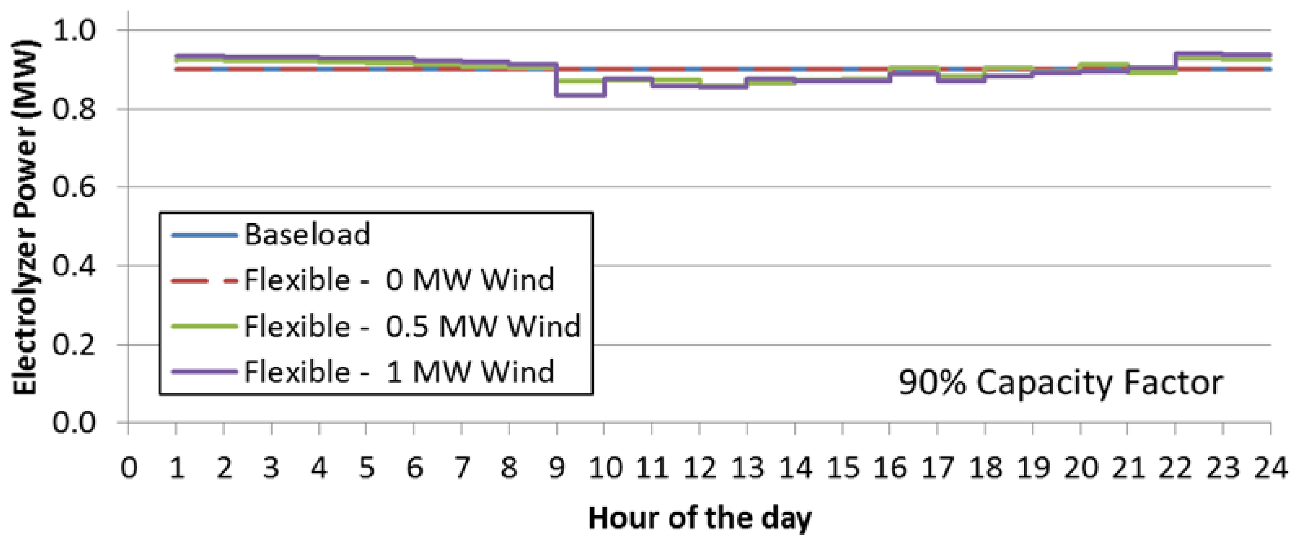




Electrolyzer operation

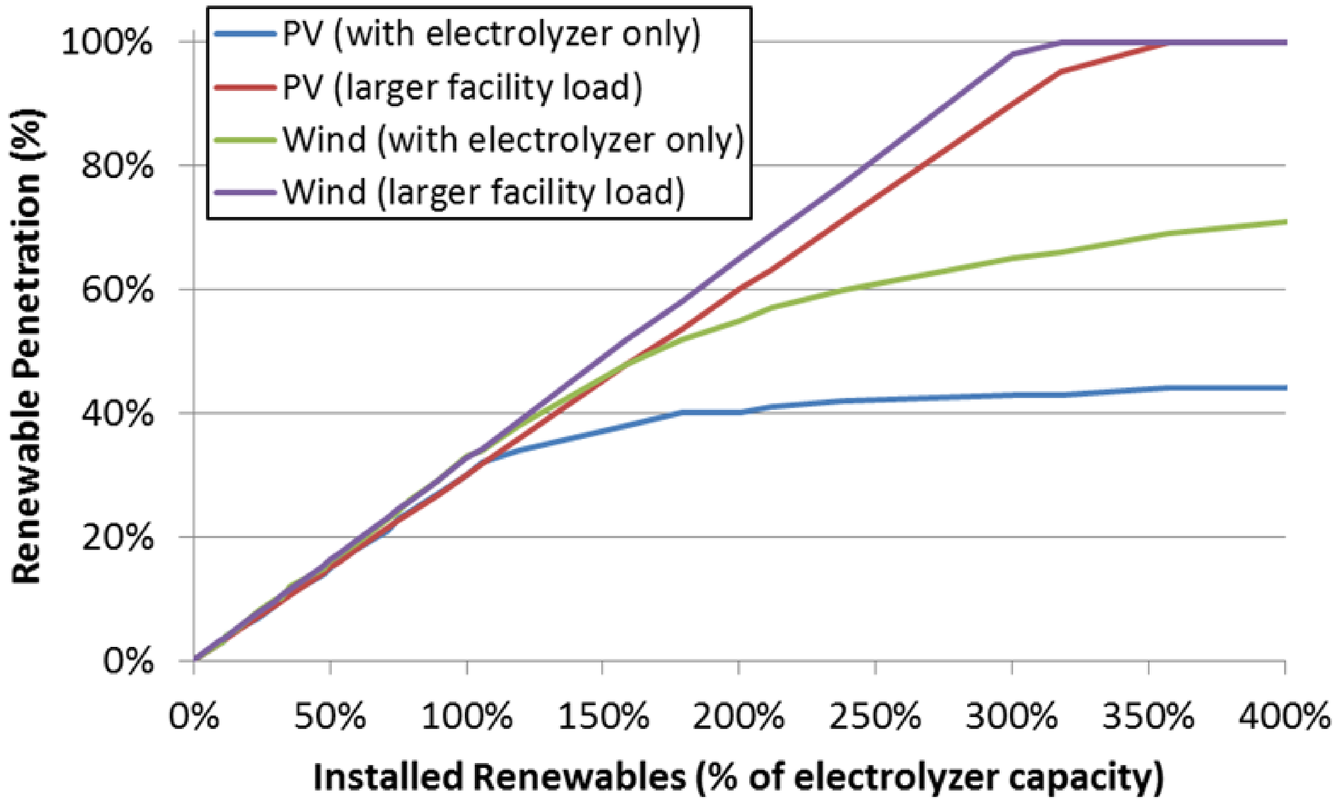
- **Optimized operation profiles**





Challenge with on-site renewables

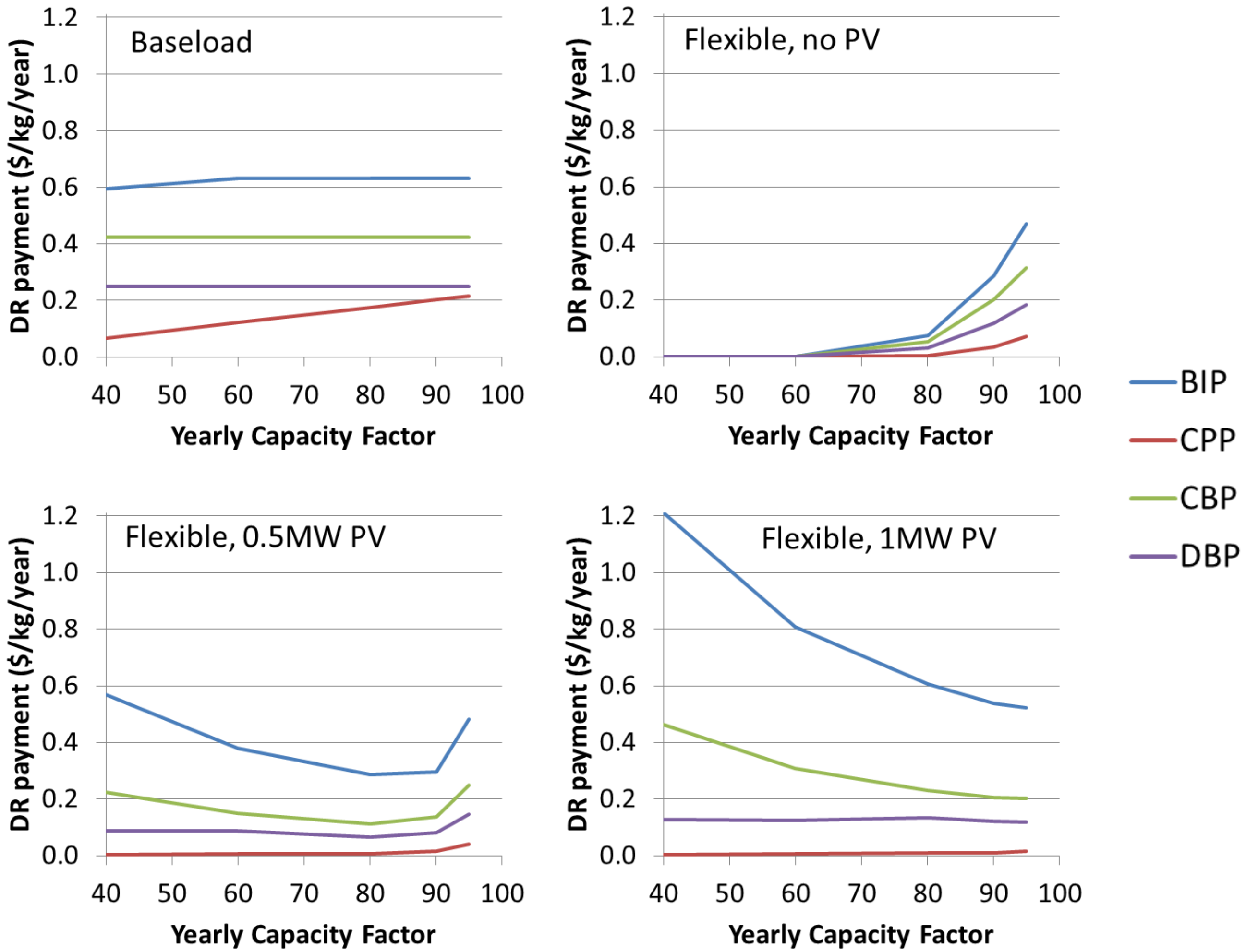
- **On-site renewables enable reduction in demand charge and electricity charge**
- **However, they can only achieve around 30% renewables without net-metering or siting at a larger facility**



Challenge with receiving on-site benefits and renewable content of hydrogen

Demand response program value (PG&E)

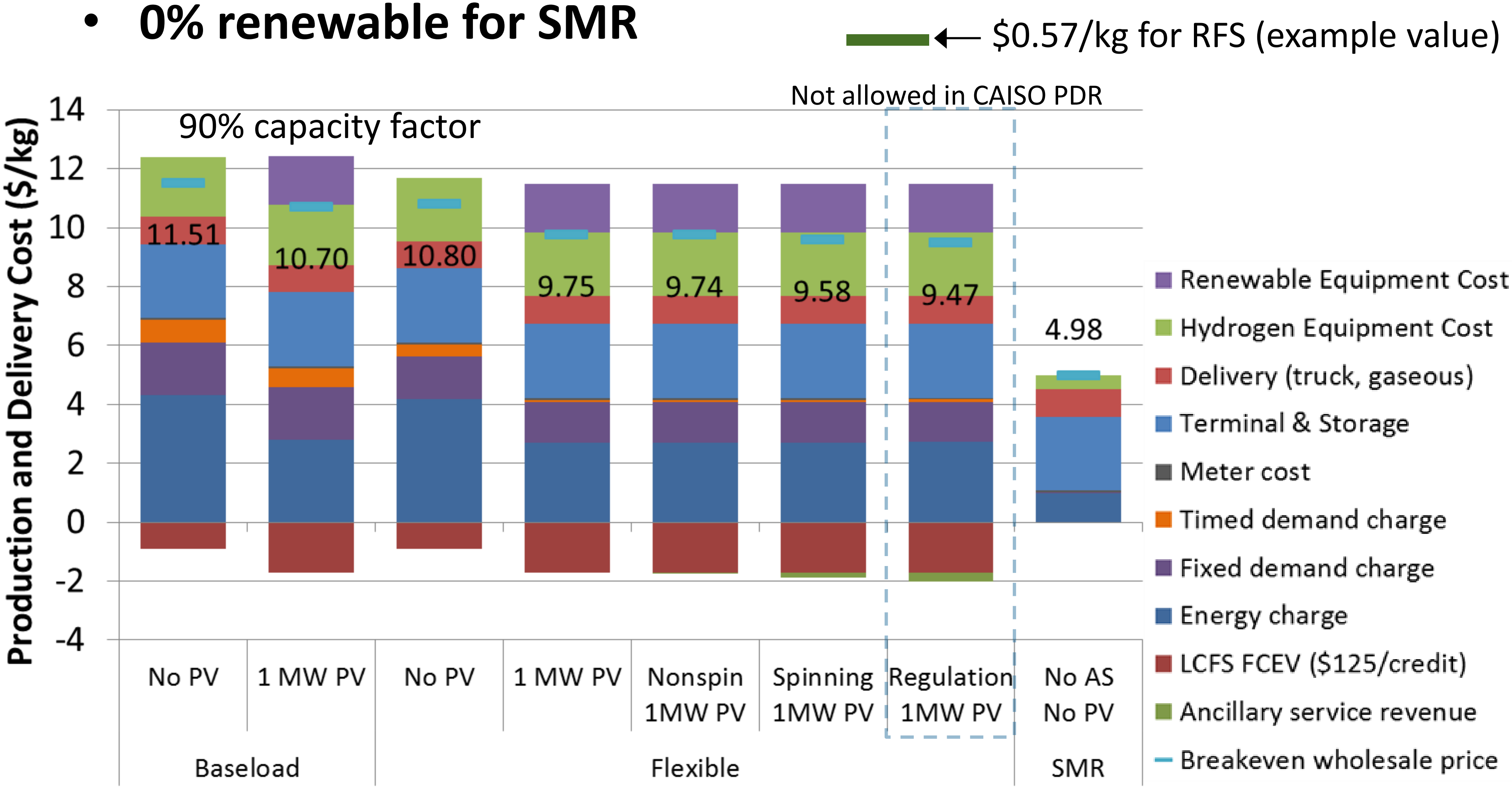
- **Baseload values are typically higher since more capacity is available during event periods**



*The firm service level for the BIP program was assumed to be zero

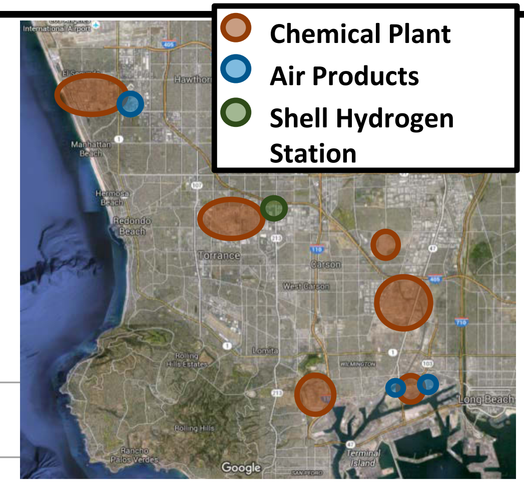
Hydrogen for FCEVs, truck delivery

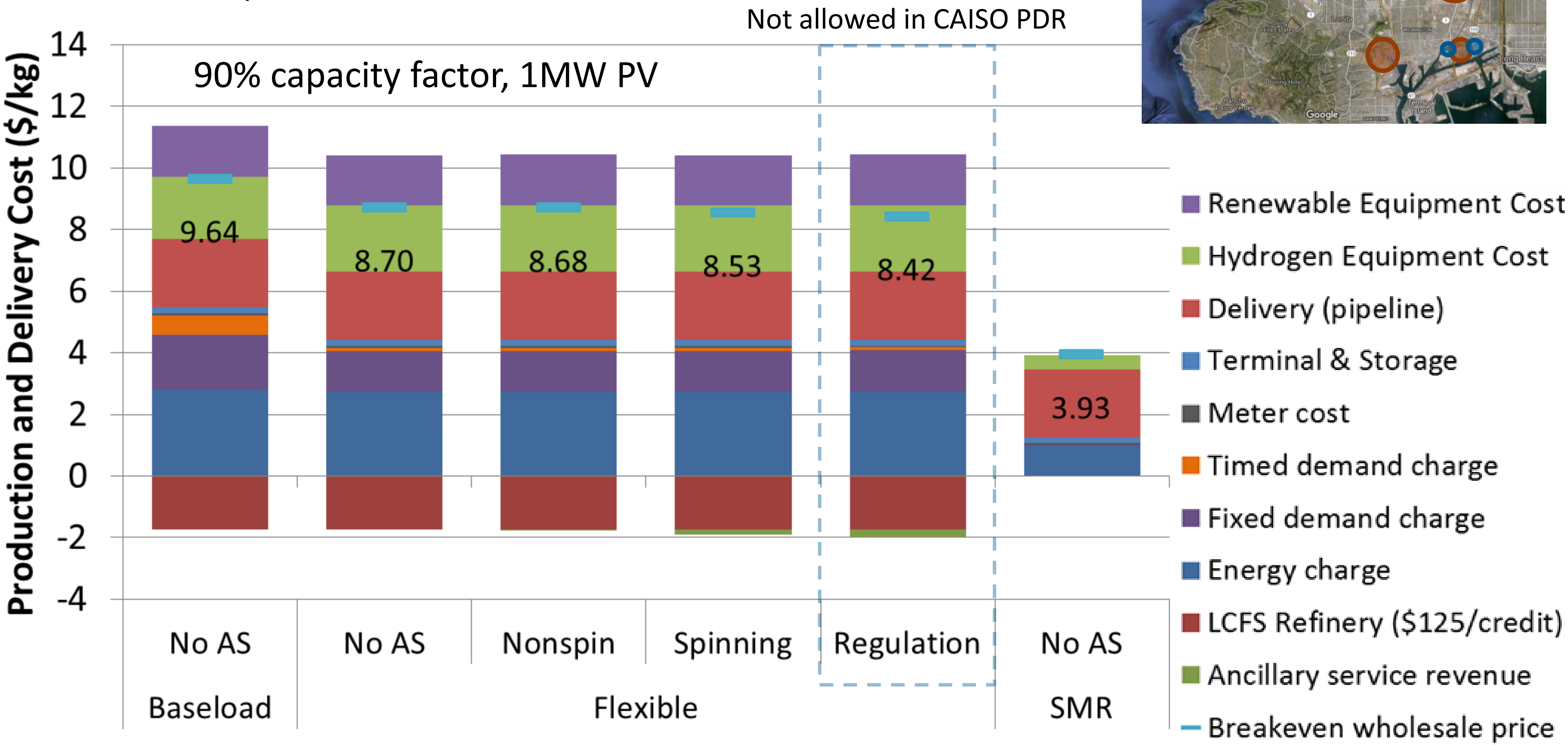
- Average revenues and costs across SCE, PG&E and SDGE
- 32% renewable electrolysis from 1MW of PV
- 0% renewable for SMR



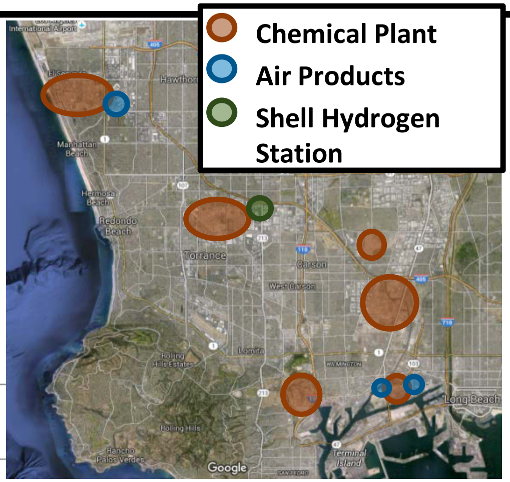
Hydrogen for FCEVs, pipeline delivery

- **Benefits**
  - Large demand (also access to hydrogen station)
  - Low cost delivery (could use existing compression equipment)
  - Qualifies for LCFS

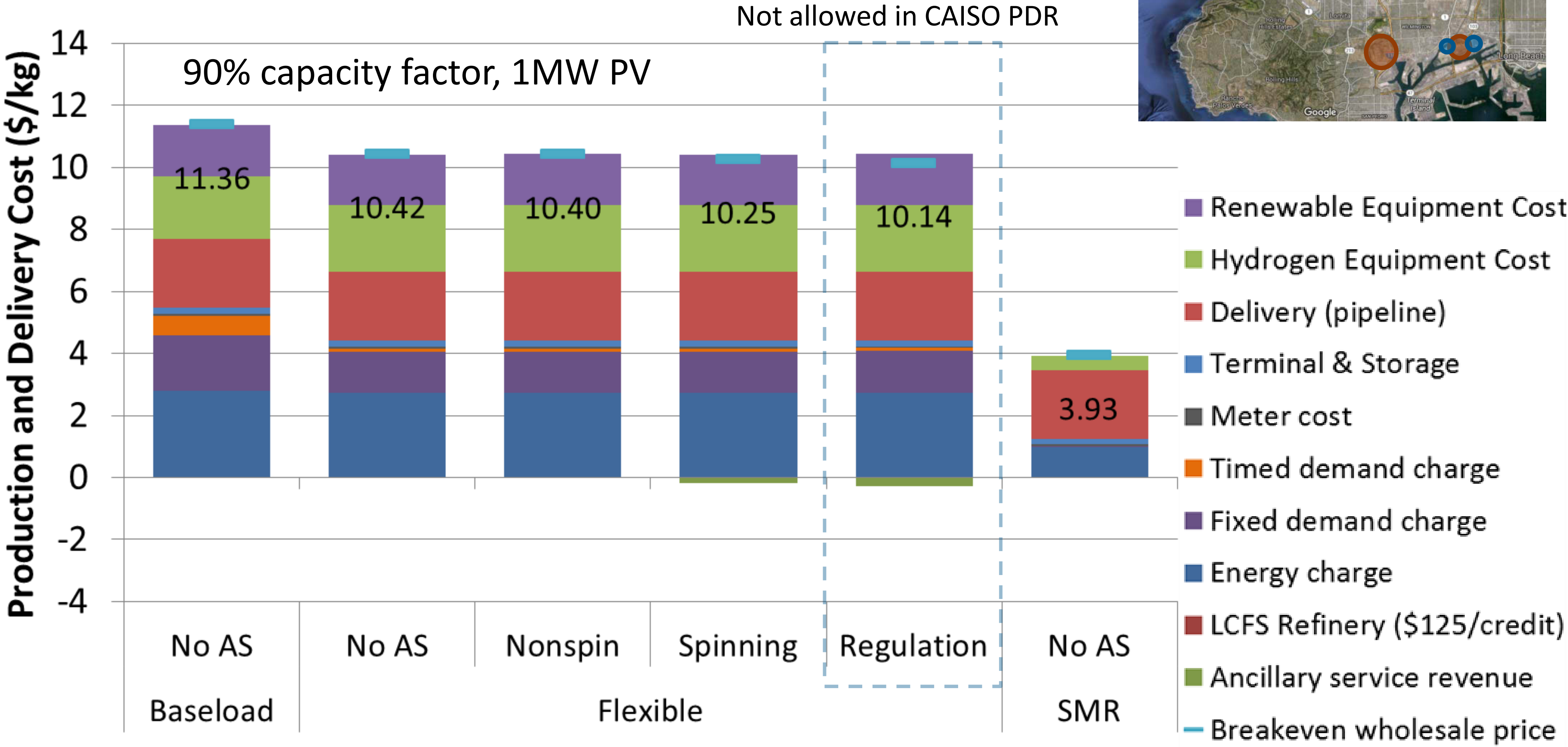




Hydrogen for Refinery, pipeline delivery

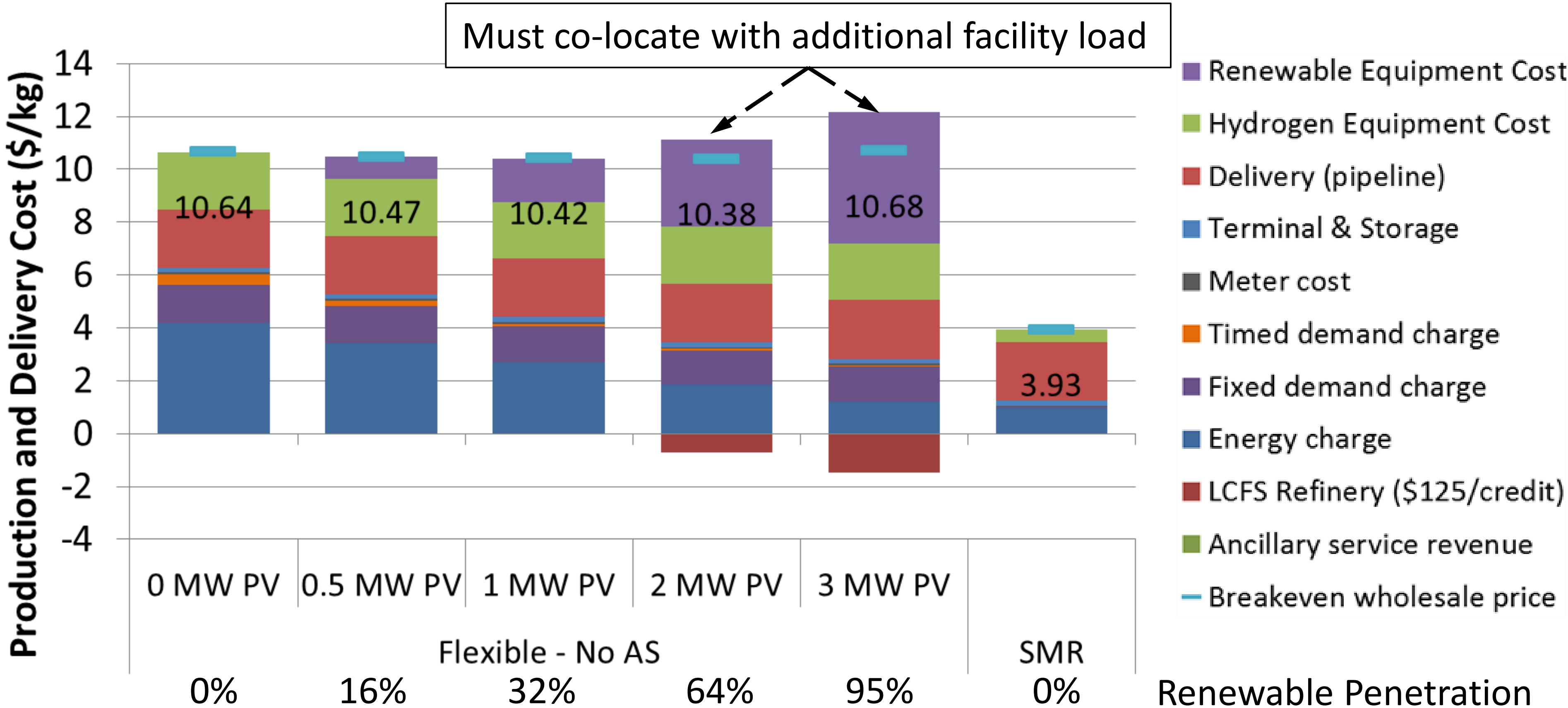


- **Benefits**
  - Large demand and qualifies for LCFS
  - Low cost delivery (use existing compression equipment)
- **Challenges**
  - LCFS does not provide enough revenue to offset cost of renewables



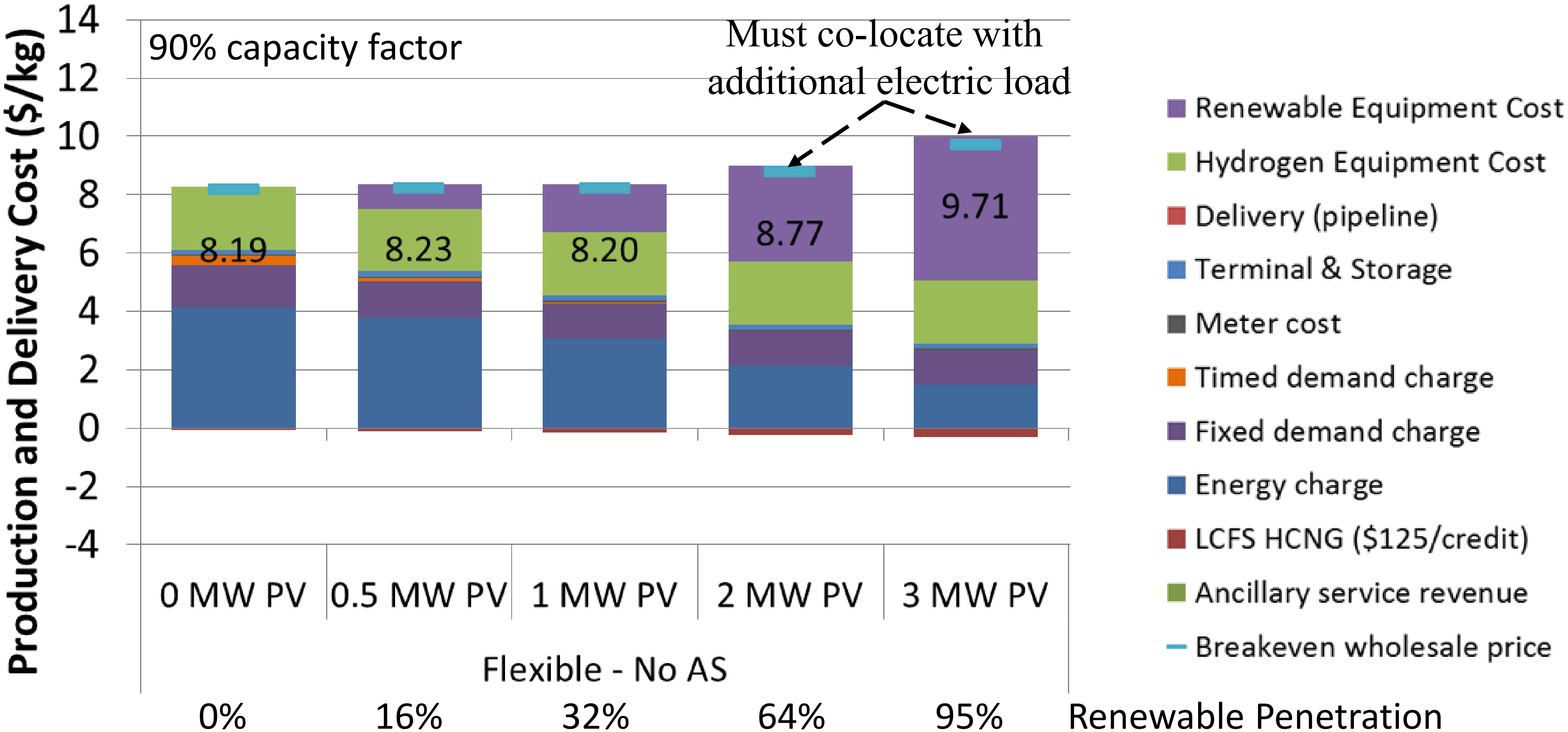
Hydrogen for Refinery, pipeline delivery

- **Co-location with additional electric load enables larger on-site renewable installation which generates LCFS credits**



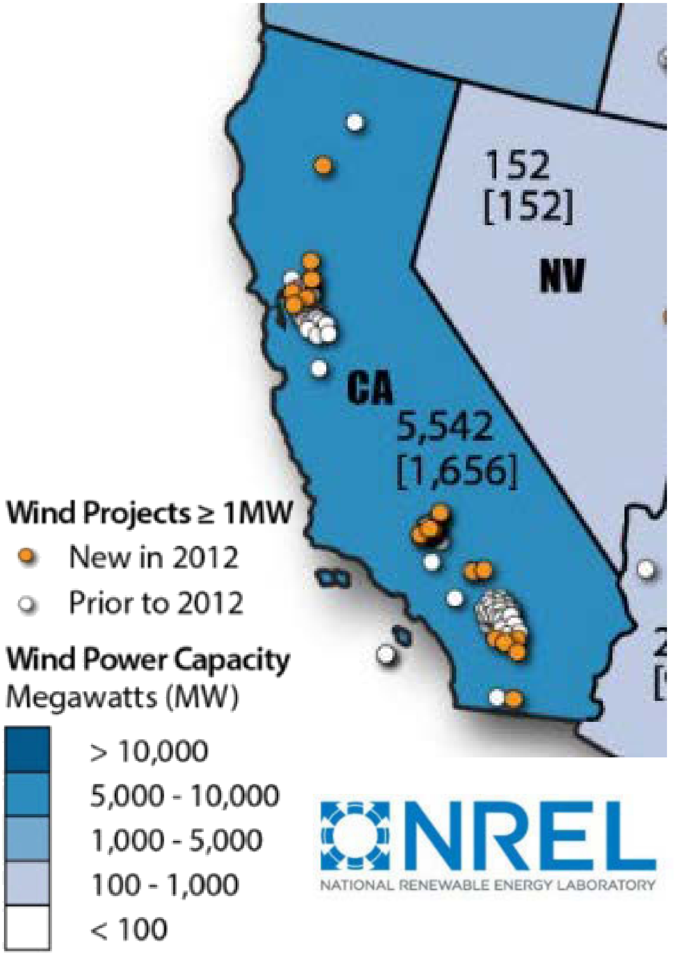
Hydrogen injection into natural gas pipeline

- Average retail natural gas price of $6.34/MMBTU for SoCalGas and PG&E
- The natural gas price equates to $0.72/kg
- LCFS accounts for between $0.08/kg and $0.31/kg
- LCFS and reductions in the cost of energy do not provide enough revenue to offset cost of renewables



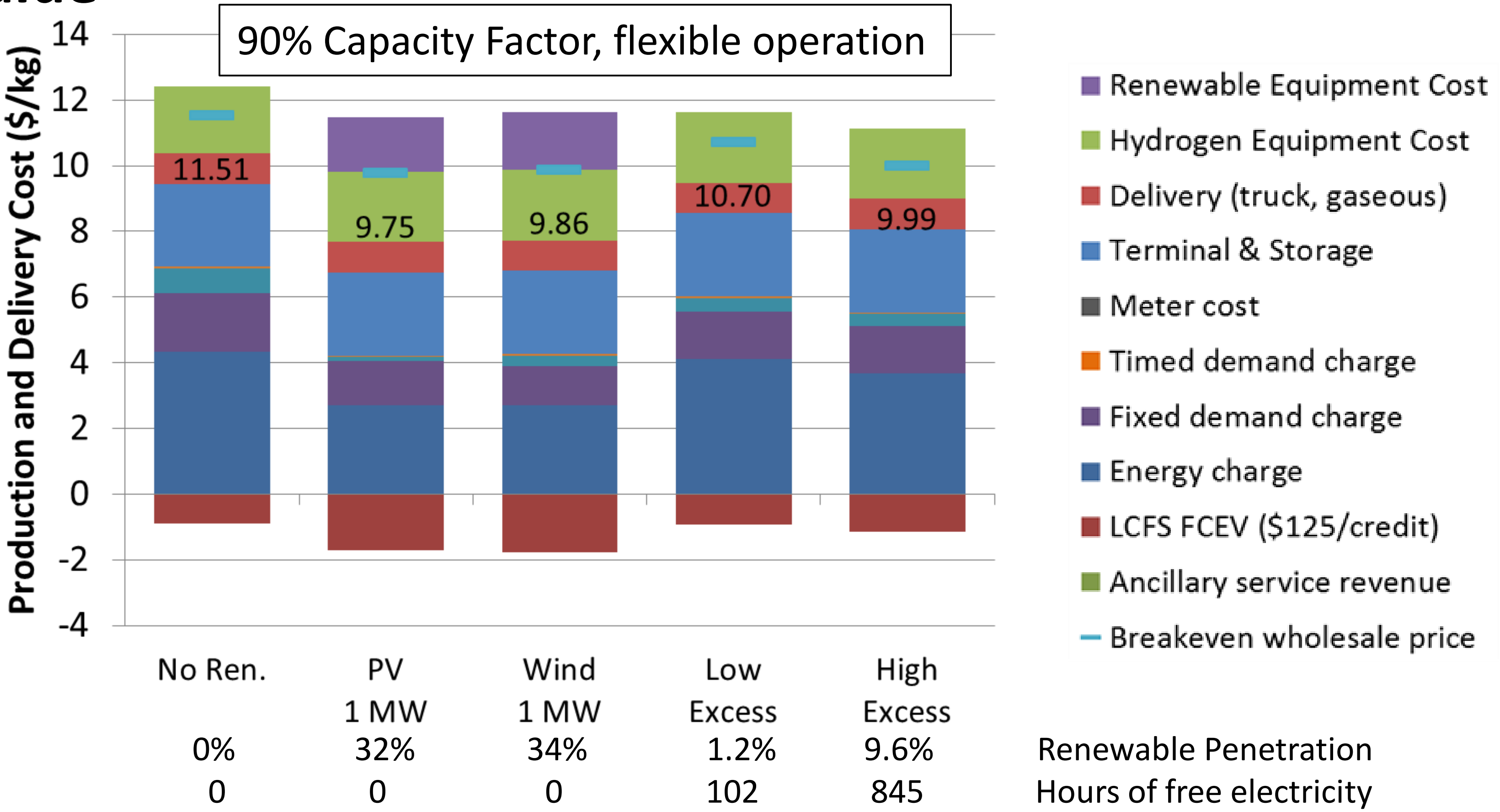
Hydrogen production with on-site renewables

- **Make use of otherwise curtailed energy**
  - Discussions with renewable providers have shown very limited hours of excess generation
  - Using 2014 LTPP modeling results from a recent NREL study, we assume two levels of excess generation. (http://www.nrel.gov/docs/fy16osti/65061.pdf)
    - 102 hours pertaining to 33% renewable penetration
    - 845 hours pertaining to 40% renewable penetration
  - Provides renewables for specified hours at no cost
  - Also, consider economic feasibility of islanded renewable microgrid
  - Solar can be distributed or centralized, while only centralized wind is considered for this study

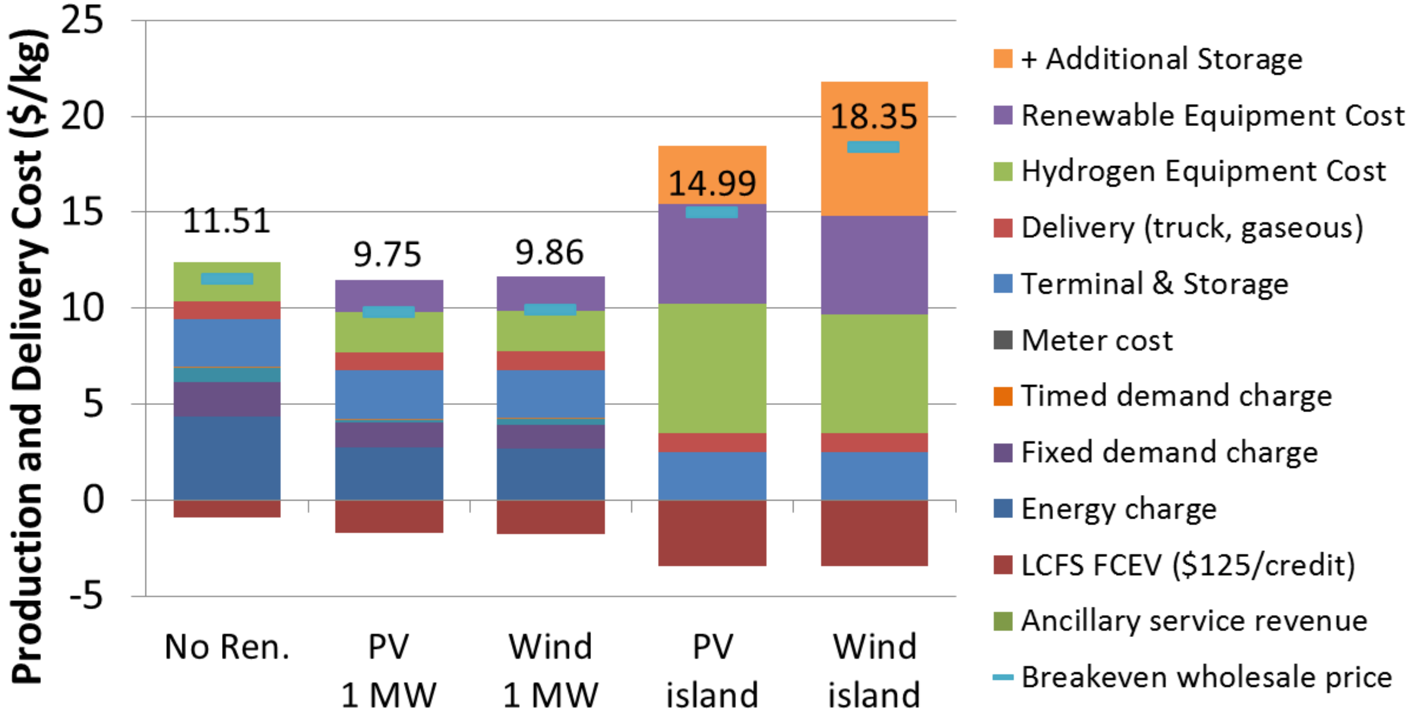


Hydrogen production with excess renewables

- **Excess generation can improve economics; however, the number of hours limits the benefit**
- **Once there is a sink for electrons they will increase in value**



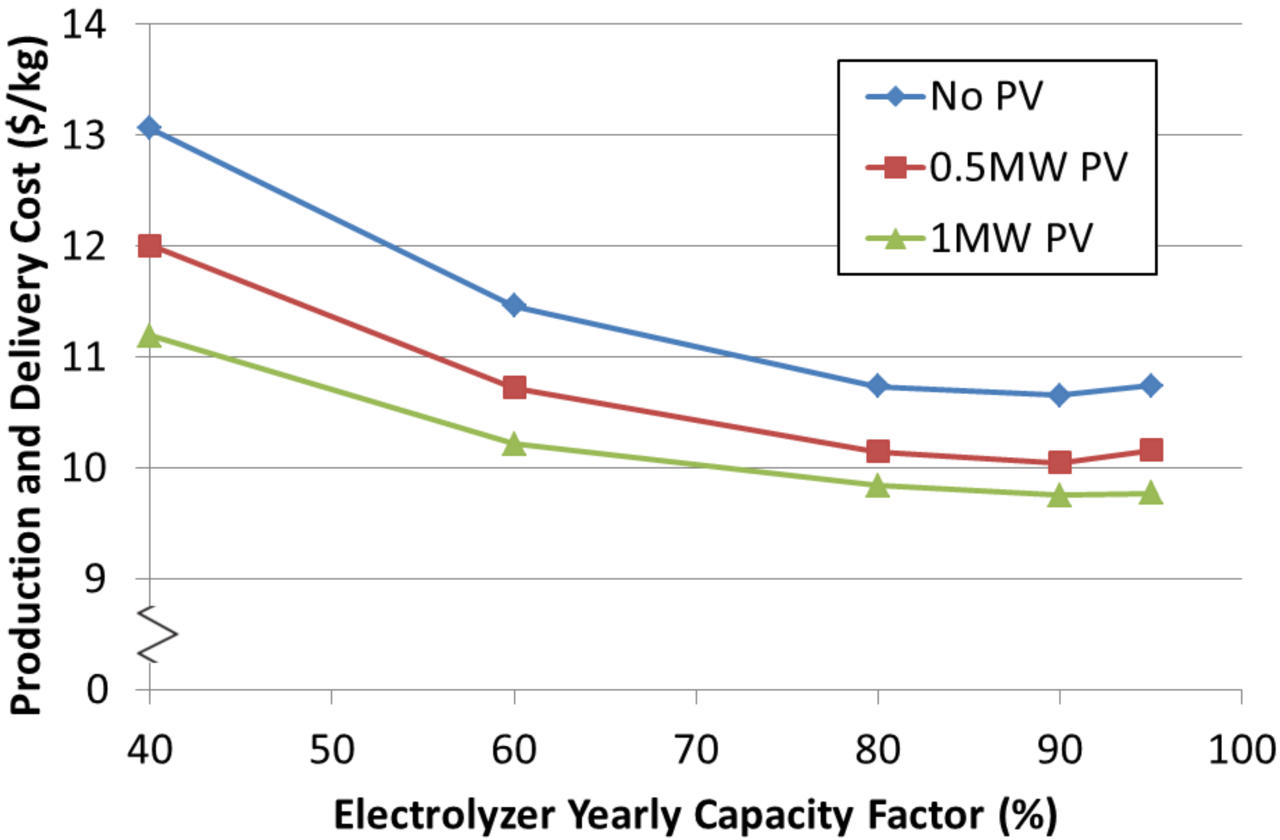
- **Must include compression, storage and delivery**
- **Islanded installations must purchase additional storage to capture entire resource**
- **experience significant costs from stranded assets**



	32%	34%	100%	100%	Renewable Penetration
74	74	74	1,602	3,831	Storage capacity (kg H_2)
398	398	398	126	137	H_2 Production (kg/day)
90%	90%	90%	27%	30%	Capacity Factor

Capacity Factor Sensitivity

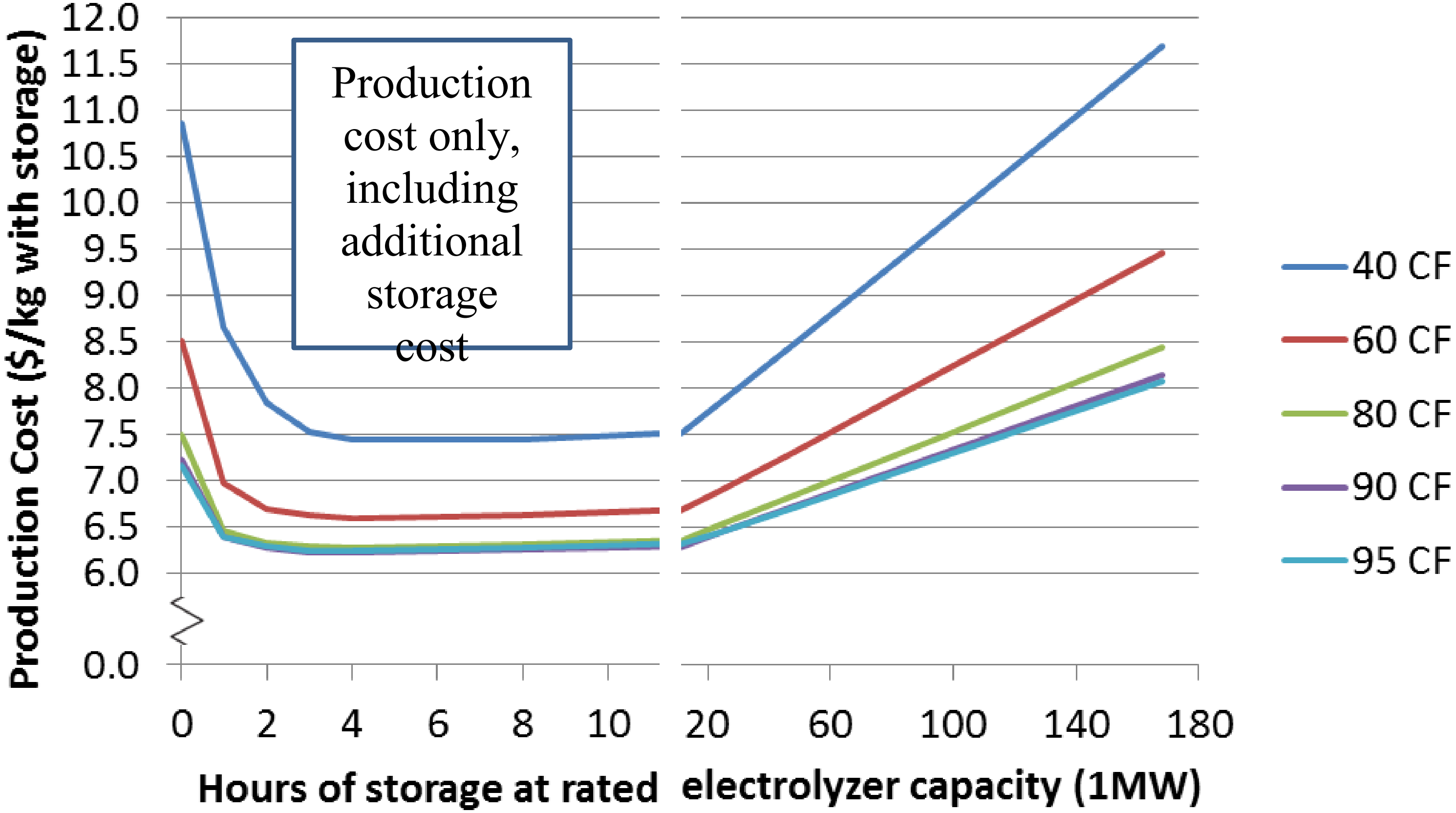
- **Must balance capital amortization with electricity prices**



The balance occurs around 90% CF for current CA utility rates

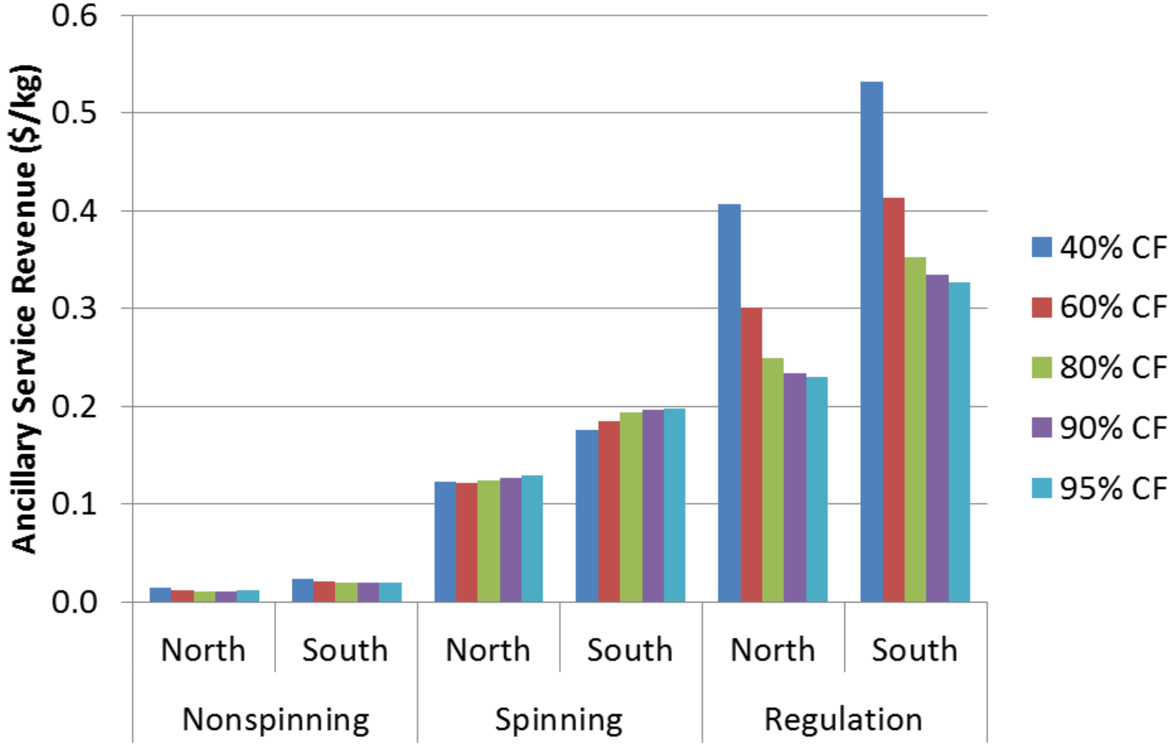
Storage Capacity Sensitivity

- **Lowest production cost around 4-8 hours**
- **Storage @ $1,000/kg for 20years with 7% interest**



Value of Ancillary Services

- **Ancillary service revenue varies significantly by markets and capacity factor (CF)**
- **We assume that resources are bid as much as possible (optimistic)**
- **Proxy Demand Resource product allows nonspinning and spinning but not regulation**



LCFS Backup Slides

LCFS Credit Opportunities

- **Credit calculation variables**

$$Credits = \left(CI_{year\ std} - \frac{CI_{actual}}{EER}\right) \times E_i \times EER \times 10^{-6}$$

Variable	Description	Value used (source)
$CI_{year\ std}$	Baseline carbon intensity	LCFS final order
CI_{actual}	Pathway's carbon intensity	See next slide
EER	Energy Economy Ratio, represents relative vehicle efficiency	LCFS final order
E_i	Energy of fuel	LCFS final order
10^{-6}	Factor used to convert grams to tons of CO_2 equivalent	LCFS final order

H2/FCV - LCFS Credit Opportunities

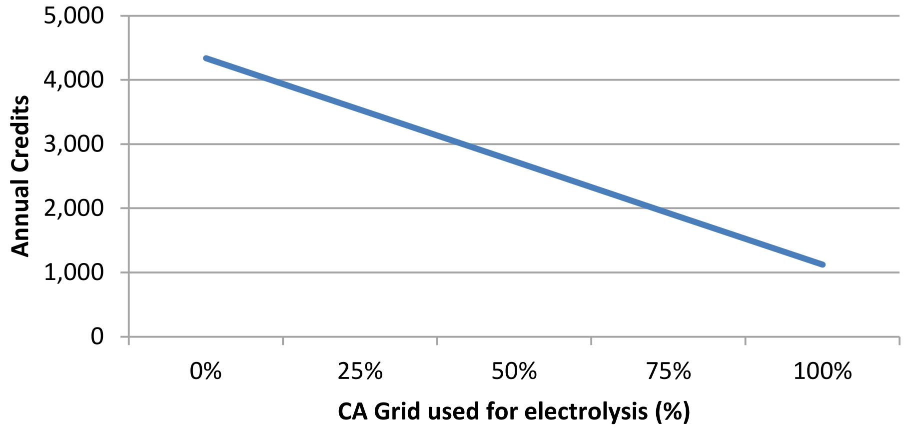
- **Electrolyzed hydrogen pathway carbon intensity**

Source of electricity	Carbon intensity	Source
California grid	105.2	LCFS final order
Renewable energy system	0	AC Transit LCFS pathway application

$$CI_{Hydrogen} = (CI_{CA\ Grid} \times \%_{CA\ grid}) + \cancel{(CI_{RE} \times \%_{RE})}$$

$$Annual\ credits = Credits \times Hydrogen\ produced\ [kg]$$

Annual Credits for Different Amounts of CA Grid Electricity (170 tons of hydrogen/yr)



HCNG - LCFS Credit Opportunities

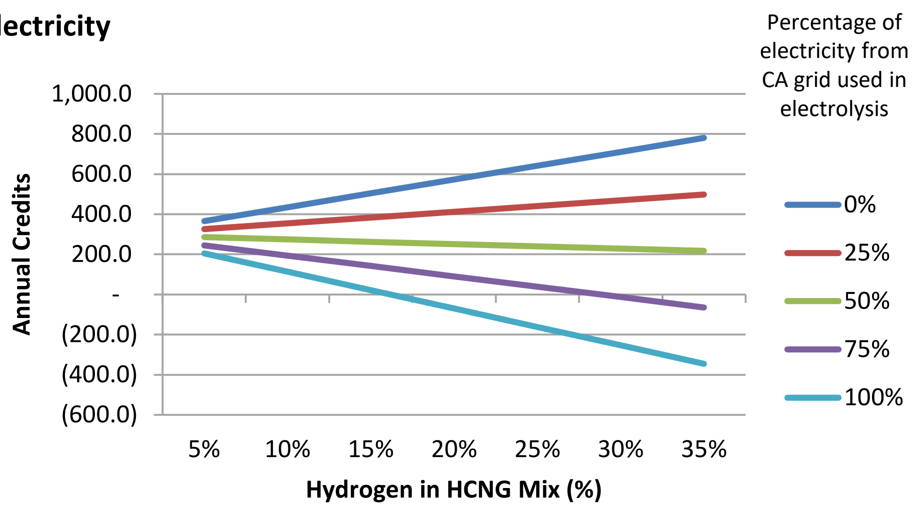
- **Hydrogen + CNG mix pathway carbon intensity**

Variable	Carbon intensity	Source
Hydrogen percentage	*	Depends on CA grid/RE mix
California grid	105.2	LCFS final order
Renewable energy system	0	AC Transit LCFS pathway application

$$CI_{HCNG} = (CI_{CA\ Grid} \times \%_{CA\ grid}) + (CI_{CNG} \times \%_{CNG})$$

$$Annual\ credits = Credits \times Hydrogen\ produced\ [kg]$$

Annual Credits for Different Amounts of CA Grid Electricity



Refinery - LCFS Credit Opportunities

- **Refinery carbon intensity**

Variable	Carbon intensity	Source
California grid	105.2	LCFS final order
Renewable energy system	0	AC Transit LCFS pathway application

$$\underbrace{CI_{Hydrogen} = (CI_{CA\ Grid} \times \%_{CA\ grid}) + \cancel{(CI_{RE} \times \%_{RE})}}$$

$$Credits = \left(CI^{H2}_{Fossil} - CI^{H2}_{Renewable}\right) D \times V(kg) \times 10^{-6}$$

Annual Refinery Credits