# Combined Heat and Power (CHP) Market Assessment Update 2011:

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Presented by:
Ken Darrow
Bruce Hedman
Eric Wong
Anne Hampson


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# Presentation Topics

- Market Characterization
  - Policy Landscape
  - Existing CHP
  - CHP Technical Potential
  - Energy Prices
  - CHP Technology Cost and Performance
- Market Forecast and Scenario Analysis
  - General Assumptions
  - Scenario Assumptions
  - Scenario Results (Base Case, Medium Case, High Case)
  - Greenhouse Gas (GHG) Emissions Reduction due to CHP
- Conclusions

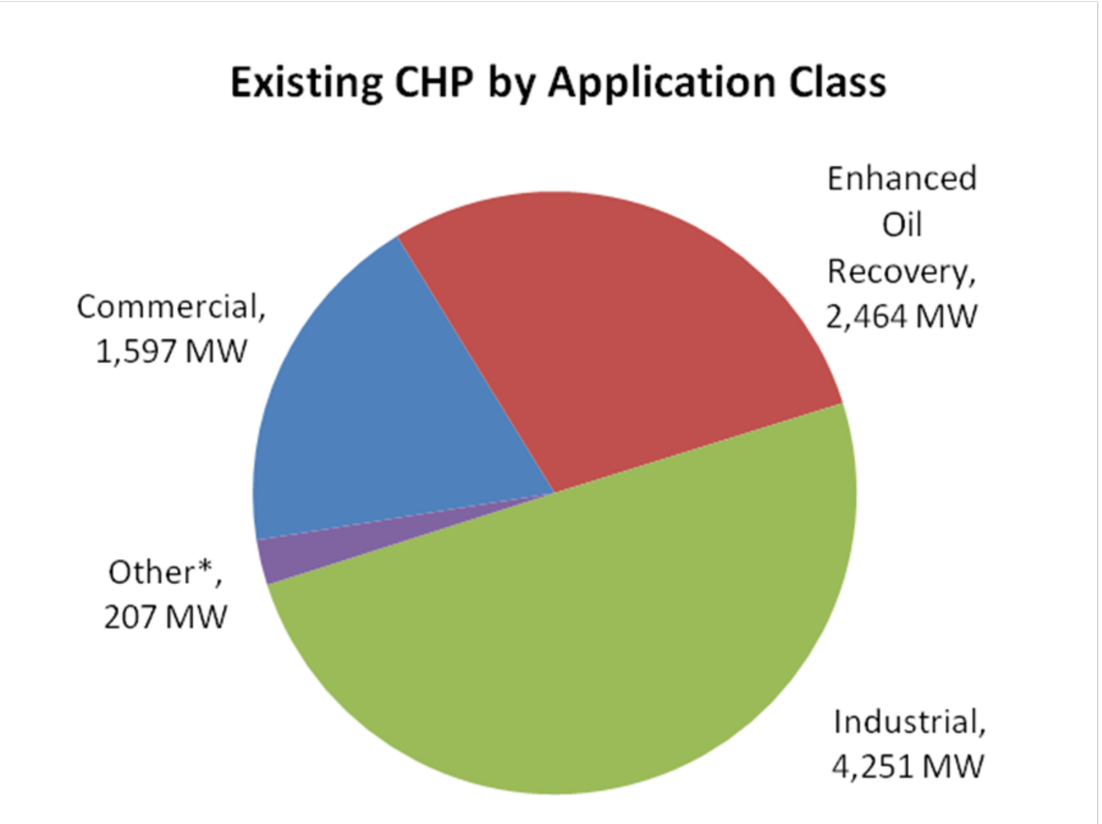
# Policy Landscape – Changes Since the 2009 CHP Market Assessment

- **Qualifying Facility (QF) Settlement** (October 2010) -- resolved outstanding disputes between utilities and qualifying facilities and establish a new CHP procurement program through 2020
- **CHP Export Feed-in-Tariff (FIT)** – Provides a price for the sale of excess power to a utility from CHP facilities less than 20 MW
- **Self Generation Incentive Program (SGIP)** – revises and extends the program by adding back non-fuel cell CHP technologies and provides funding through January 2016
- **33% Renewable Portfolio Standard (RPS)** – requires utilities to have 33% of their generating capacity be renewable power by 2020
- **Cap and Trade** – establishes a market trading program for carbon dioxide emissions allowances that is designed to bring state emissions of greenhouse gases down to a specified level by 2020
- **Distribution System Interconnection Settlement –** provides stakeholders a forum to develop a revised Rule 21 that addresses interconnection issues, especially for project exporting power

# Existing CHP in California

- 1,202 Sites
- 8,518 MW

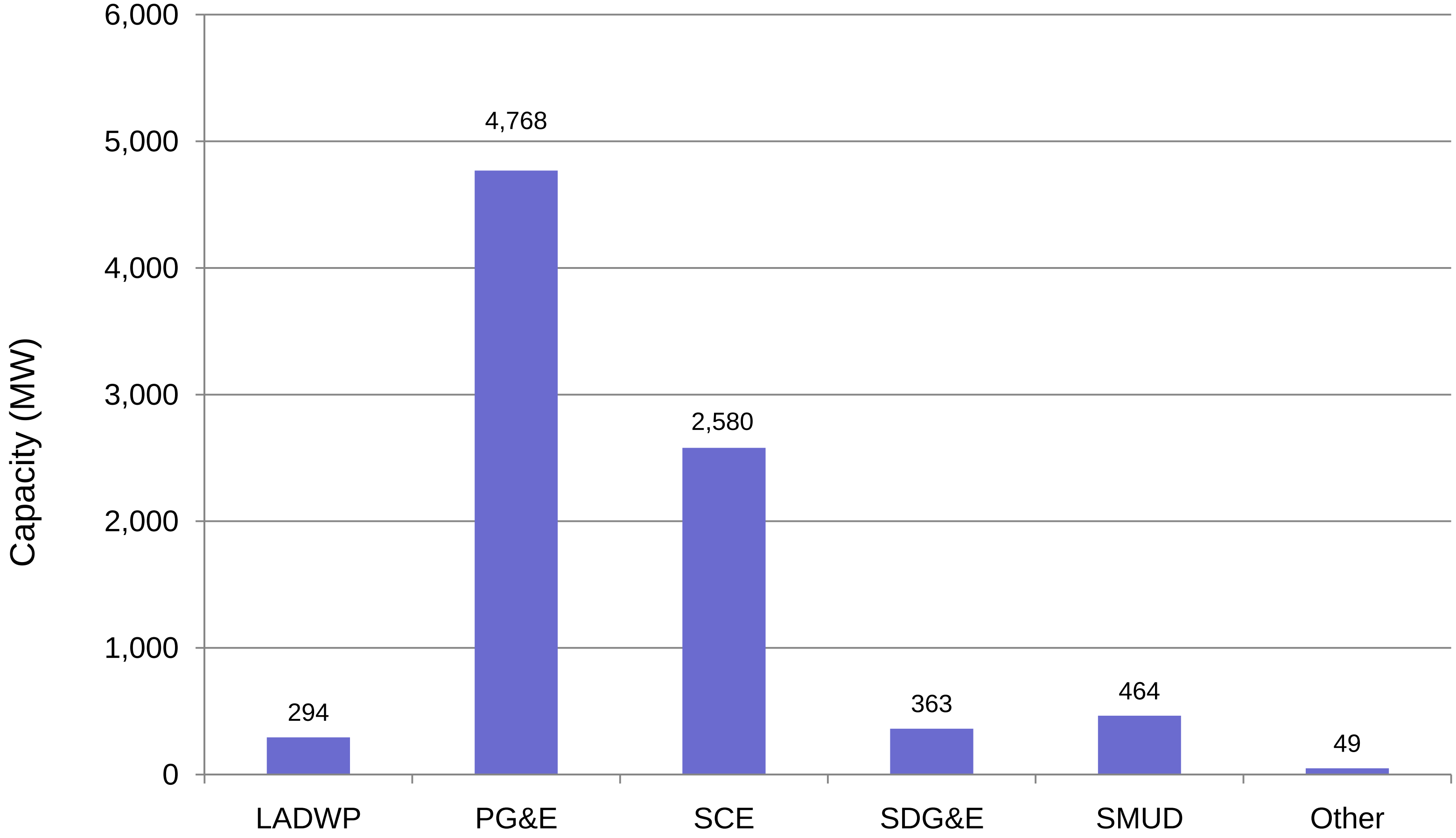
Result of data reconciliation process with Energy Commission and Public Utilities Commission (CPUC) CHP data




*Other = Agriculture and minerals

Source: ICF CHP Installation Database

# Existing CHP by Utility Region




Source: ICF CHP Installation Database

# CHP Technical Market Potential Estimation

- Evaluation of markets with good electric load factor and thermal loads to utilize thermal energy from CHP system
  - Process industries – chemicals, refinery, paper, food, primary metals
  - Enhanced oil recovery
  - Large and medium commercial institutional – education, health care, hotels, health clubs, prisons
  - Use of thermal for air conditioning – commercial and institutional markets above plus retail, office buildings, and large multifamily complexes
- Characterization of sites with technical potential (number of sites and MW capacities)
  - Identify sites by business line using Dun & Bradstreet database
  - Estimate electric and thermal loads based on ICF analysis of usage by business line
  - On-site vs. export potential determined based on power to heat ratios for smaller sites and specific industry analysis for large sites
- Subtraction of existing CHP to determine Remaining On-site and Export Technical Potential

# CHP Technical Potential Summary: Total Electrical Generating Potential

**Technical Potential, MW**

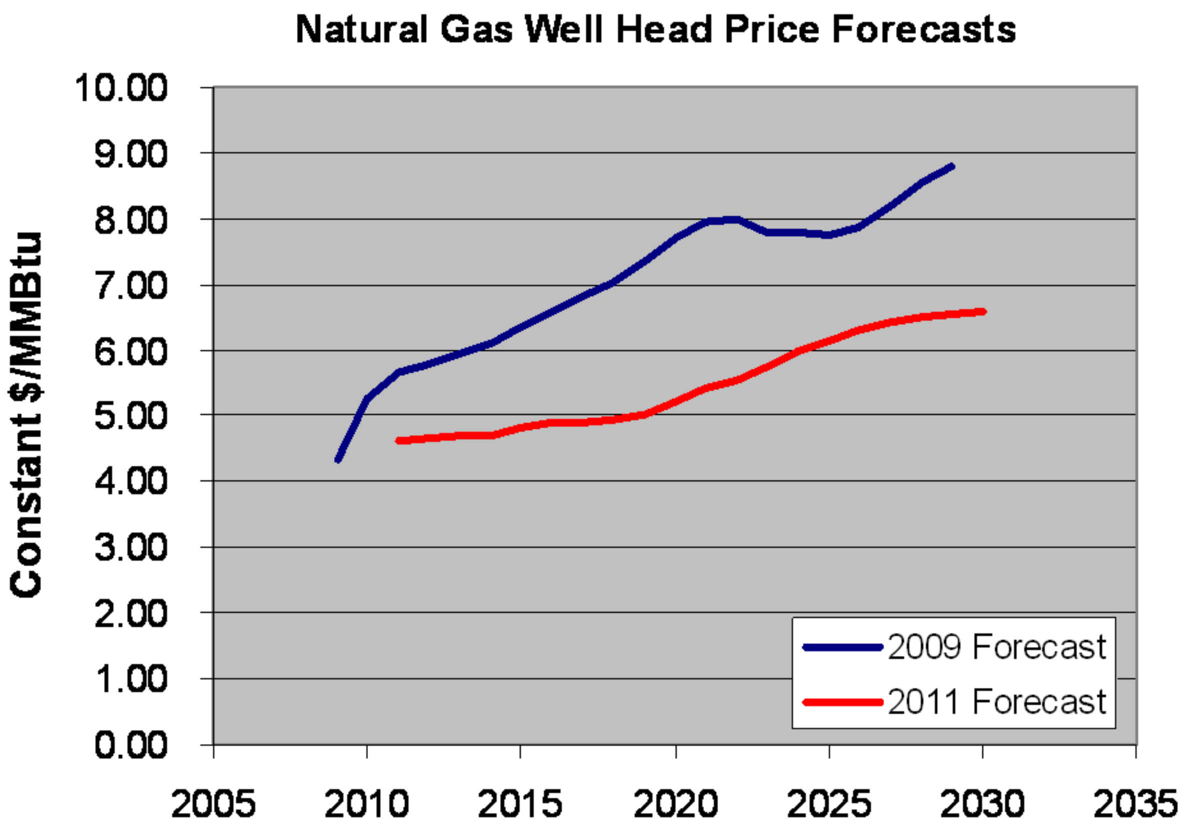
| Market Type | 50-500 kW | 500-1000 kW | 1-5 MW | 5-20 MW | >20 MW | Total |
|---|---|---|---|---|---|---|
| Industrial Existing On-site | 688 | 375 | 1,042 | 818 | 385 | 3,309 |
| Commercial/Residential Existing | 2,078 | 846 | 1,650 | 929 | 447 | 5,950 |
| Export Existing | 0 | 0 | 286 | 901 | 3,847 | 5,034 |
| Industrial New On-site | 60 | 29 | 68 | 51 | 20 | 228 |
| Commercial/Residential New | 471 | 191 | 384 | 154 | 64 | 1,264 |
| Export New | 0 | 0 | 9 | 40 | 131 | 180 |
| **Total** | **3,297** | **1,441** | **3,439** | **2,893** | **4,894** | **15,964** |

- Existing facilities represent businesses that exist today that have unmet CHP potential – either through new or expanded CHP
- New facilities represent an estimate of economic growth in the target market segments over the next 20 years

# Energy Price Analysis: General Assumptions

- Future price movements based on Energy Information Administration (EIA) 2011 Annual Energy Outlook 2011 (AEO2011) Reference Case,
  - Electricity price trends from Western Electricity Coordinating Council-California region estimates of the Electricity Market Module
  - Natural gas wellhead prices based on AEO2011 estimate of Henry Hub price
  - EIA case does not include effects of California RPS or Cap and Trade
- Retail electric rates
  - Based on analysis of current tariffs for three largest investor owned and two largest municipal utilities
  - Future price growth estimated based on fixed real T&D rates and generation rates escalated based on the costs of power from a combined cycle power plant
  - *CHP savings rate* based on the current tariff analysis of the avoided costs due to CHP operation
- Retail Gas Rates
  - Gas utility hub price differentials from Henry Hub price based on CEC 2011 natural gas price forecast
  - CHP and boiler rate markups calculated from current firm delivery tariffs

# 2011 Natural Gas Wellhead Price Forecast



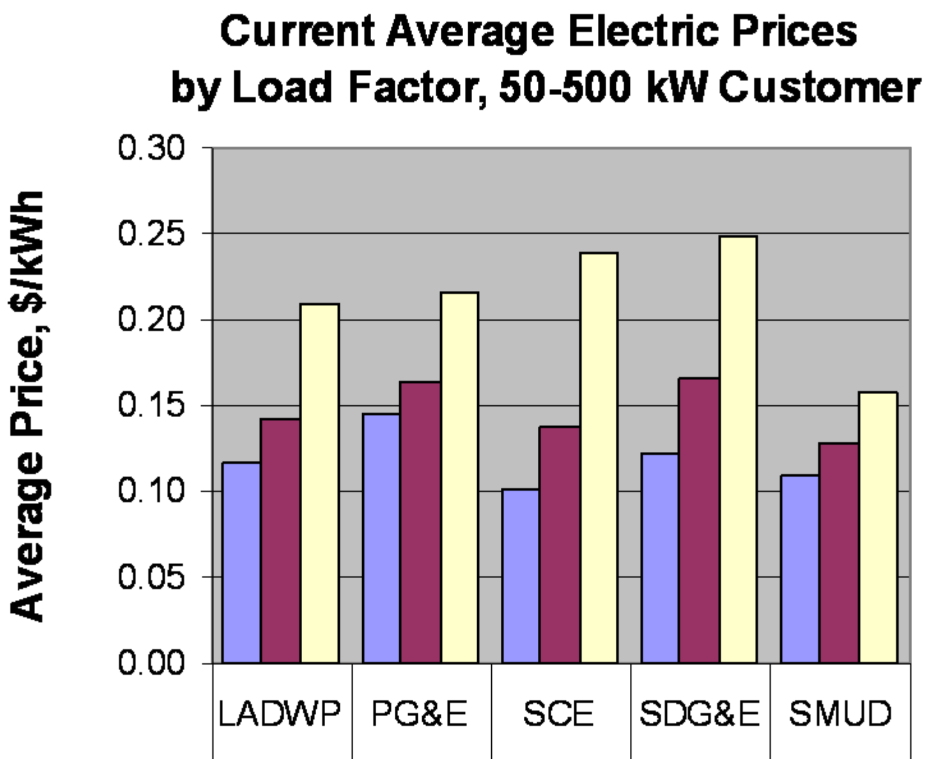

- Outlook for future wellhead gas prices well below 2009 EIA forecast
- Reduction based on low cost shale gas replacing LNG as the marginal future source of supply

# Intrastate Gas Transportation Costs

| Utiltiy / Customer Size Classes | 50-500 kW | 500-1,000 kW | 1-5 MW | 5-20 MW | >20 MW |
|---|---|---|---|---|---|
| Boiler Load, $/million Btu | | | | | |
| PG&E | $2.46 | $2.18 | $1.74 | $1.34 | $0.93 |
| SCG | $2.34 | $1.79 | $1.27 | $0.85 | $0.69 |
| SDG&E | $3.18 | $2.75 | $2.66 | $2.64 | $2.63 |
| CHP Load, $/million Btu | | | | | |
| PG&E | $0.52 | $0.35 | $0.31 | $0.29 | $0.30 |
| SCG | $0.61 | $0.58 | $0.57 | $0.25 | $0.25 |
| SDG&E | $0.71 | $0.68 | $0.67 | $0.35 | $0.35 |

- Transportation costs for boiler load based on standard firm transportation rates for estimated boiler load by CHP customer class
- CHP customers get special gas transportation rate – rates are lower due to the special rate and the increased consumption for the CHP system (P/H ratio assumed for this analysis 1:2)

# Electric Price Forecast: 50-500 kW

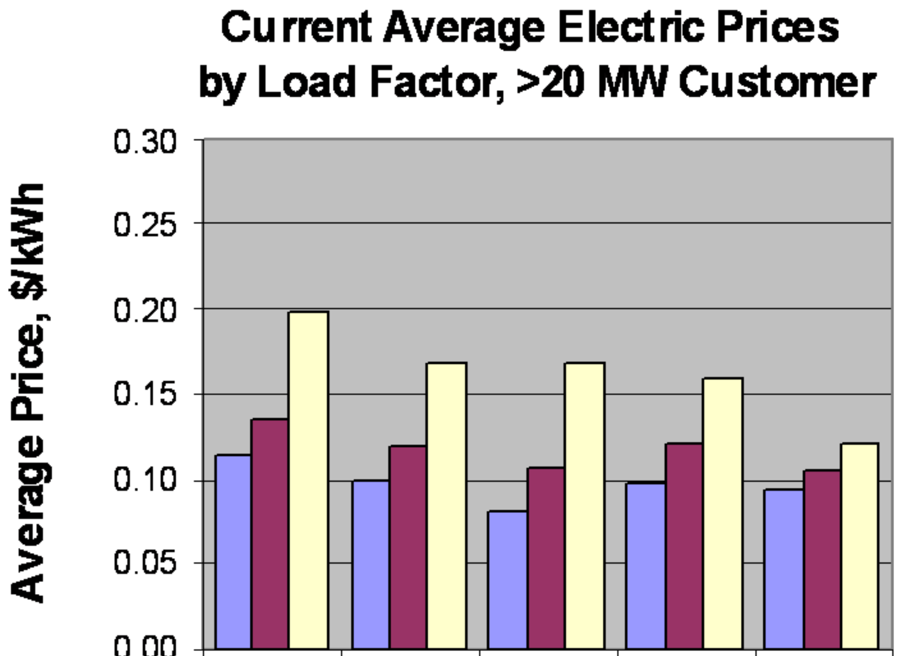



| | LADWP | PG&E | SCE | SDG&E | SMUD |
|---|---|---|---|---|---|
| High Load Factor | $0.1166 | $0.1447 | $0.1020 | $0.1212 | $0.1094 |
| Low Load Factor | $0.1414 | $0.1638 | $0.1378 | $0.1662 | $0.1274 |
| Peak AC | $0.2100 | $0.2150 | $0.2390 | $0.2478 | $0.1574 |

**Utility / Tariff :**

- LADWP: A-2b Primary
- PG&E: A-10 TOU Secondary
- SCE: GS-3TOU Secondary
- SDG&E: AL-TOU Secondary
- SMUD: GS-TOU3 Secondary

# Electric Price Forecast: Greater than 20 MW

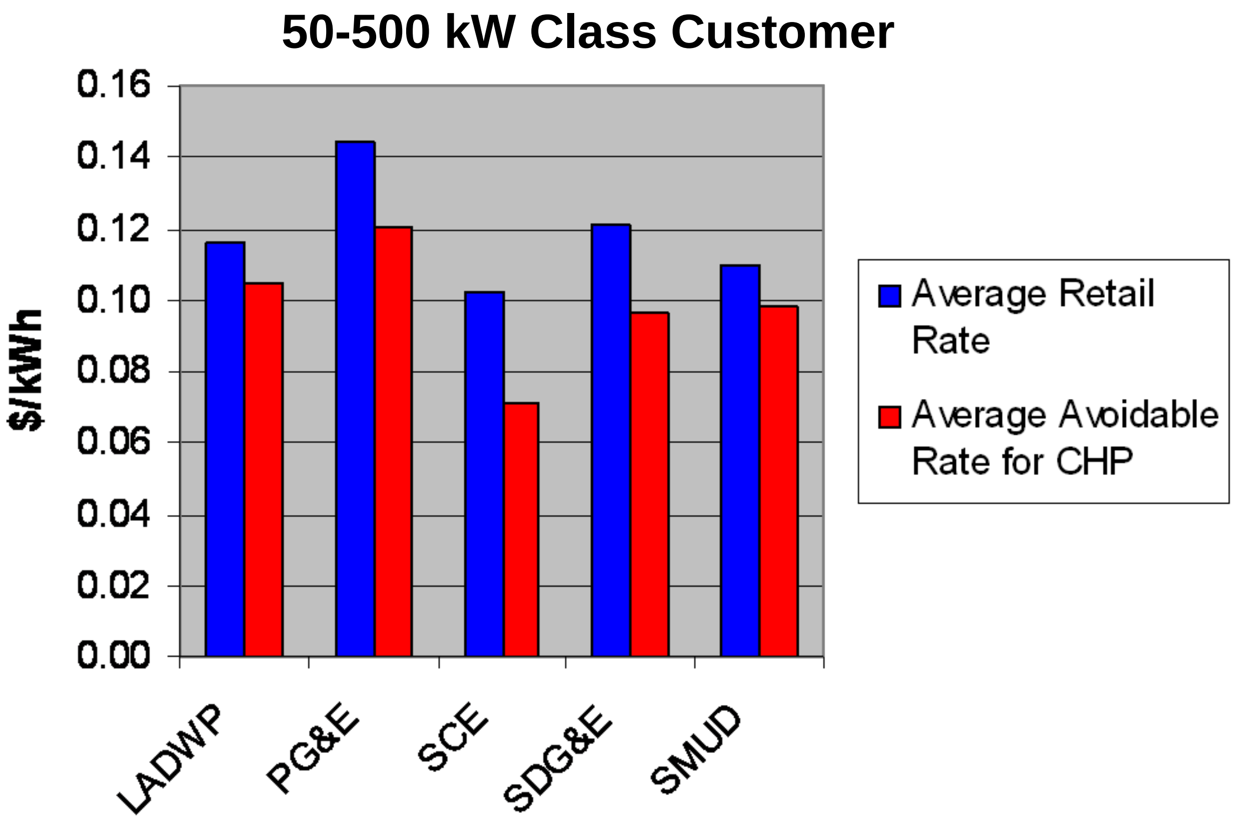



| | LADWP | PG&E | SCE | SDG&E | SMUD |
|---|---|---|---|---|---|
| High Load Factor | $0.1134 | $0.0997 | $0.0811 | $0.0966 | $0.0942 |
| Low Load Factor | $0.1360 | $0.1199 | $0.1065 | $0.1217 | $0.1044 |
| Peak AC | $0.1983 | $0.1678 | $0.1675 | $0.1585 | $0.1216 |

**Utility / Tariff :**

- LADWP: A-3a Subtransmission
- PG&E: E-20-Transmission
- SCE: GS 8-TOU Transmission
- SDG&E: AL-TOU-Subtransmission
- SMUD: GS-TOU1 Transmission

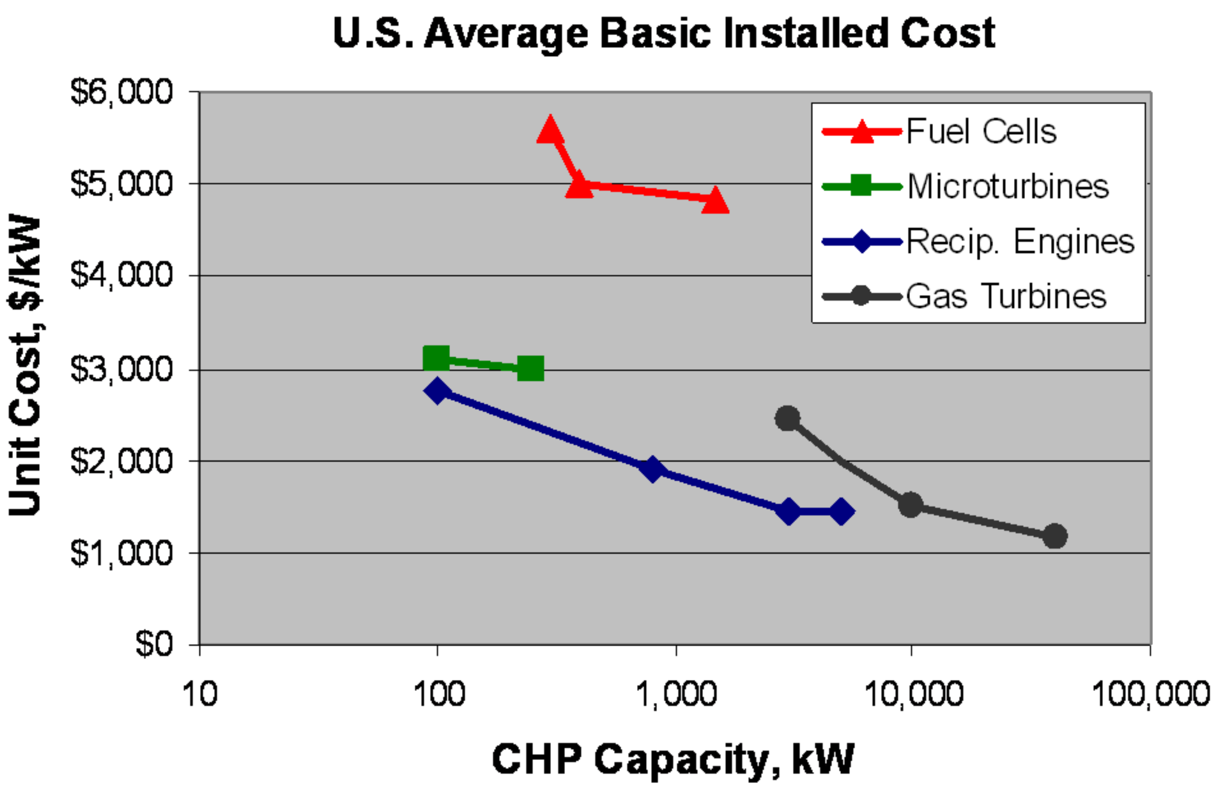
# Share of Retail Rates that are Avoidable with CHP




## Unavoidable Costs

- Customer charges ($/meter/month)
- Forced outages that trigger demand charges
- Non-bypassable Charges (per kWh)
- Standby reservation charges
- 10-20% of retail costs unavoidable, up to 2.7 cents/kWh for high load factor customers

# CHP Technology Costs




Log scale

- 12 CHP technologies characterized
  - Capital cost – shown
  - Heat rate
  - Thermal available
  - Operating and maintenance
- Capital cost adjustments
  - California costs 3-10% higher
  - Emissions after-treatment
  - SGIP and tax credits
  - Other capital incentives
- Payback based on gas rate and avoidable electric costs

# Base Case Policy Assumptions

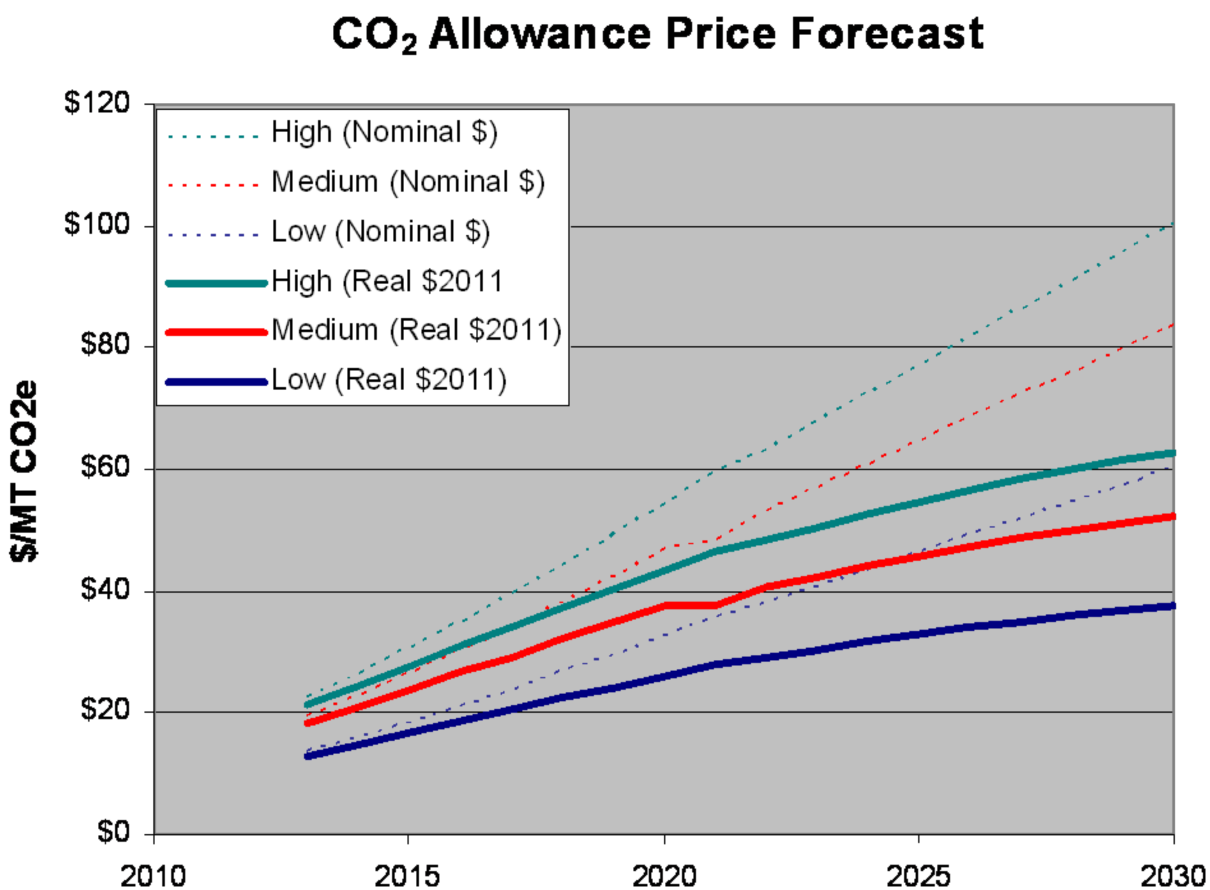
- Cap and Trade
- 33% Renewable Portfolio Standard
- SGIP with program expiration January, 2016
- AB 1613 export pricing for CHP under 20 MW
- Short Run Avoided Cost (SRAC) export pricing for CHP over 20 MW

Details on following slides

# Cap and Trade GHG Allowance Assumptions

- Quantity Assumptions
  - Based on average GHG emissions for electricity generation – from Energy and Environmental Economics (E3) GHG Calculator (Version 3c) prepared for the CPUC
  - CHP based on carbon content of the incremental natural gas fuel required for new systems
- Price Assumptions
  - 2009 Market Price Referent (MPR) analysis based on Synapse forecast – used in the joint IOU proposal and site rulemaking R.11-03012
  - 90% reimbursement of cost increase for retail electric rates
  - No reimbursement for effective fuel cost increases for onsite CHP systems

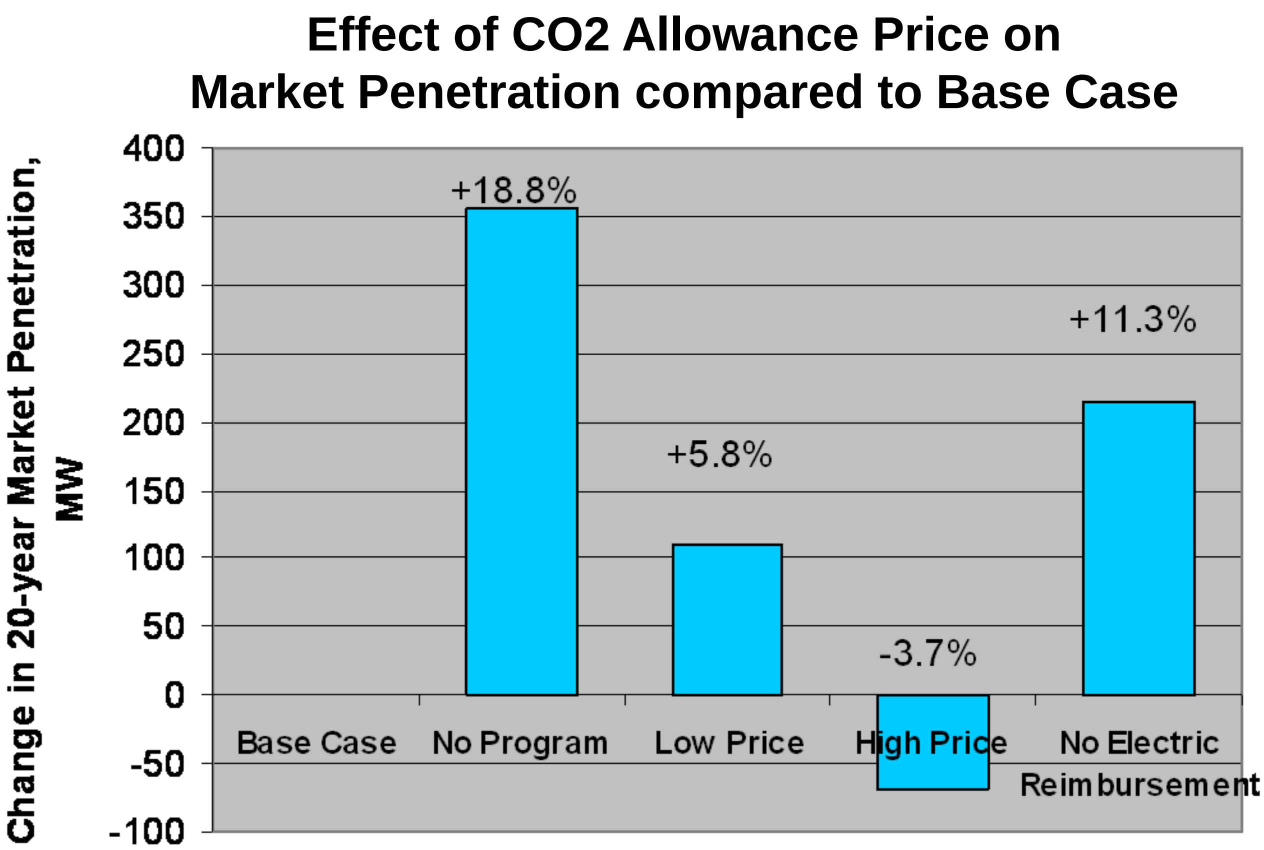
# Cap and Trade: $CO_2$ Allowance Price Forecast




- Based on Synapse Forecast for 2009 MPR – joint IOU proposal and site rulemaking
- Linear extrapolation to 2030
- Medium case used for the analysis
- Converted to 2011 real dollars for the model inputs at 2.5% per year (MPR assumption)

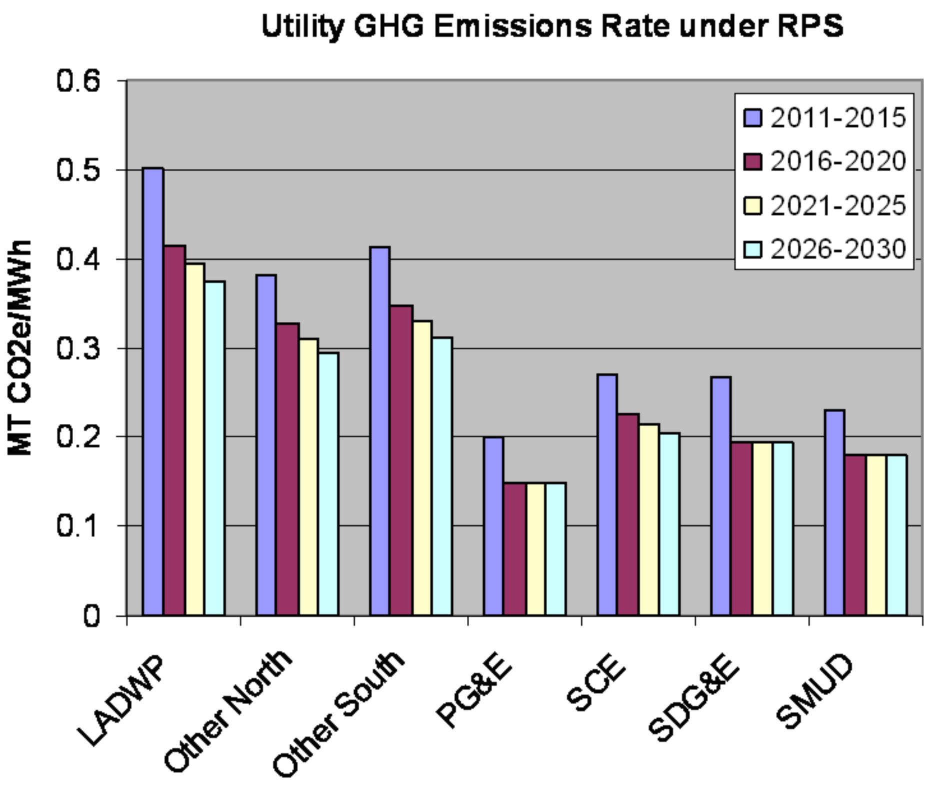
Medium Case 2020 Price: $46.80/MT ($37.47 2011 $)

# Sensitivity: $CO_2$ Allowance Price




- Base Case
  - Medium $CO_2$ price track
  - 90% electric ratepayer reimbursement

# Cap and Trade: GHG Emissions Rates




## Utility GHG Emissions for Cap and Trade

- Figure based on GHG Calculator through 2020 – Accelerated Policy Case (Case 2: 33% RPS and high energy efficiency)
- Assumes 33% RPS in effect
- After 2020, the 3 utilities with the lowest emissions rates remain constant through 2030 (PG&E, SDG&E, and SMUD)
- Other 4 utility areas assumed to reduce emissions an average of 5% every 5 years

## CHP GHG Emissions for Cap and Trade

- CHP emissions rates based on incremental gas consumption at 117 lbs/CO2e per MMBtu

# 33% Renewable Portfolio Standard – Impact on Retail Electric Rates

| | 2011-2015 | 2016-2020 | 2021-2025 | 2026-2030 |
|---|---|---|---|---|
| RPS Electric Adder, $2011/kWh | $0.0049 | $0.0131 | $0.0164 | $0.0164 |

Source: E3 GHG Calculator (V3c)

- Based on GHG Calculator – Scenario 2: Accelerated Policy Case – 33% RPS and High Energy Efficiency – Average price increase to 2020 is 1.64 cents/kWh
- Cost increase assumed to remain constant in real terms after 2020

# SGIP with Expiration in 2016

| Technology Type | Incentive ($/W) |
|---|---|
| Conventional CHP | |
| Internal Combustion Engine – CHP | $0.50 |
| Microturbine – CHP | $0.50 |
| Gas Turbine - CHP | $0.50 |
| Emerging Technology | |
| Fuel Cell- CHP or Electric Only | $2.25 |

- 20% CA manufacturer adders not modeled
- Fuel cell incentive reduces by 10% per year, all other technologies reduce by 5% per year
- Program assumed terminated in 2016

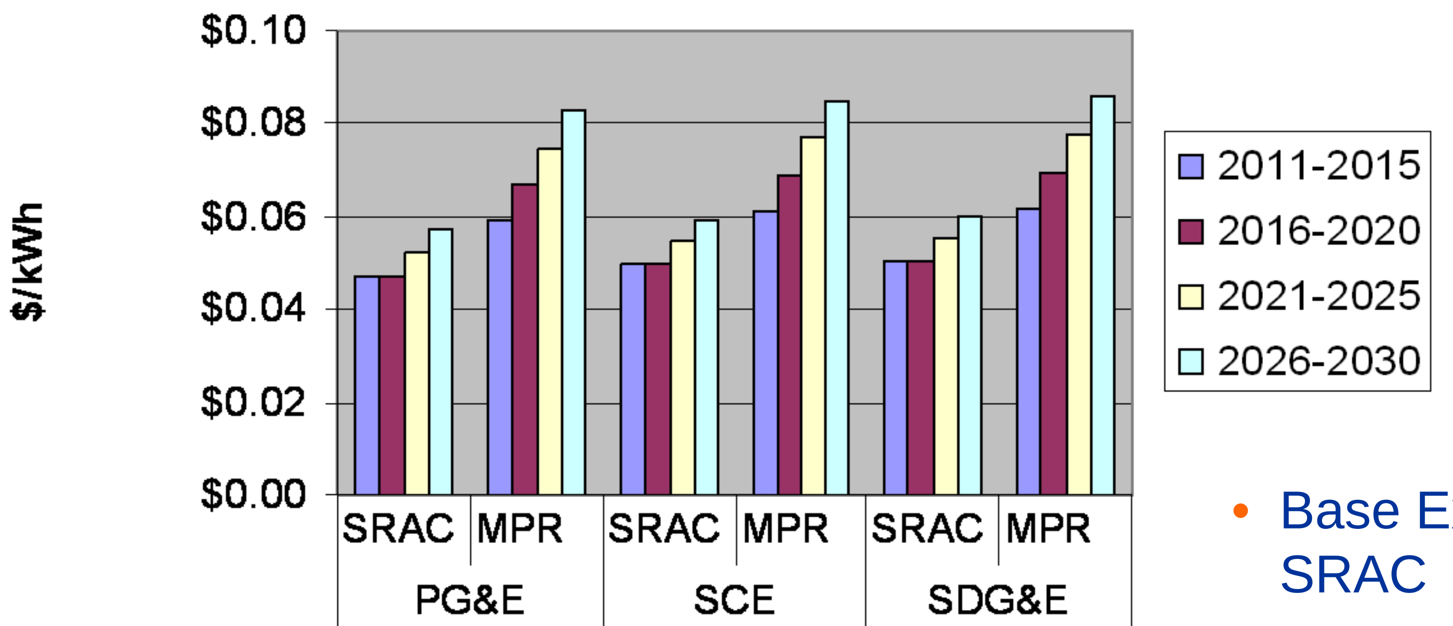
- 50% of payment up front – 50% over 5 years in equal installments if system maintains a minimum of 80% load factor
- Lower load factor operation annual payments are prorated proportionally
- All sizes can participate – payments equal 100% on first MW, 50% on second MW, 25% on third MW

# AB 1613 Export Pricing

| AB 1613 Export Prices | 2011-2015 | 2016-2020 | 2021-2025 | 2026-2030 |
|---|---|---|---|---|
| AB 1613 FIT Basis | $0.0611 | $0.0631 | $0.0691 | $0.0739 |
| 50-500 kW | $0.0611 | $0.0631 | $0.0691 | $0.0739 |
| 500-1,000 kW | $0.0611 | $0.0631 | $0.0691 | $0.0739 |
| 1-5 MW | $0.0605 | $0.0624 | $0.0685 | $0.0732 |
| 5-20 MW | $0.0605 | $0.0624 | $0.0685 | $0.0732 |
| >20 MW | $0.0610 | $0.0630 | $0.0690 | $0.0738 |

- AB 1613 FIT for systems less than 20 MW in all scenarios
- Export assumed to be a constant annual amount – averaging the time period multipliers to one
- Customers exporting more than 1 MW pay scheduling charges
- Pricing terms are designed to reflect electric system long run marginal avoided cost

# Export Pricing for Large CHP




| | PG&E SRAC | PG&E MPR | SCE SRAC | SCE MPR | SDG&E SRAC | SDG&E MPR |
|---|---|---|---|---|---|---|
| 2011-2015 | $0.047 | $0.059 | $0.049 | $0.061 | $0.050 | $0.061 |
| 2016-2020 | $0.047 | $0.067 | $0.049 | $0.069 | $0.050 | $0.069 |
| 2021-2025 | $0.052 | $0.074 | $0.054 | $0.076 | $0.055 | $0.077 |
| 2026-2030 | $0.057 | $0.082 | $0.059 | $0.085 | $0.060 | $0.085 |

- Base Export Price = SRAC
- Medium and High Export Price = 2011 Draft MPR adjusted to gas price forecast used in this analysis

# Medium Case Policy Assumptions

- 33% RPS (same as in the Base Case)
- SGIP with planned phased reduction – program extended based on a programmed phased reduction of incentives over time
  - 5% reduction per year for conventional
  - 10% per year reduction for emerging until emerging dollar value equals conventional – then declining at the same rate as conventional
- Aggressive export – MPR pricing for over 20 MW and strong market response for projects larger than 5 MW
  - MPR price 25-35% higher than SRAC price (from previous slide)
  - Higher Market response for paybacks less than 5 years (Backup material Figure A-2)

# High Case Policy Assumptions

- Includes the following Medium Case Policy Assumptions
  - SGIP with planned phased reduction
  - RPS
- Reimbursement of GHG allowance component of CHP fuel costs for onsite CHP
- No non-bypassable charges (NBCs) and elimination of “double” demand charges
  - NBCs are eliminated from IOU electric tariffs for CHP
  - No CHP outage demand charges applied when standby reservation charge is applied
  - This increases the avoidable electric costs for CHP by 1-2 cents/kWh for the IOUs depending on the utility and the rate category
  - For high load factor customers, the share of avoidable charges to retail rates ranges from 89-95% compared to the existing rates where the share ranges from 80-90%

# High Case Assumptions, continued

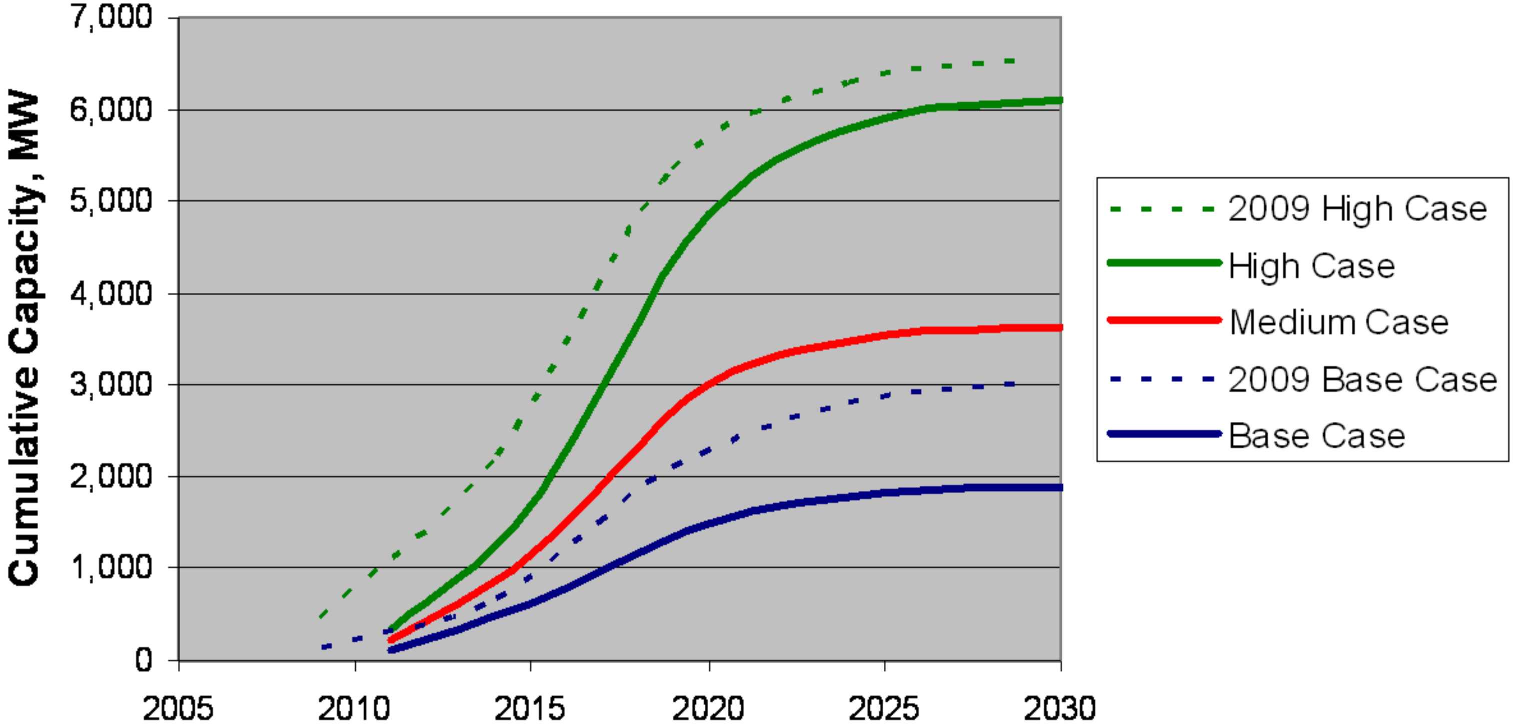
- High Electric focus electric utility participation
  - Assumed utility ownership of large CHP with greater focus on electricity production
  - Large export CHP technical potential for sites greater than 50 MW based on combined cycle technology cost and performance – effectively increasing large export potential by 50%
  - Same export pricing assumptions as in the medium case
- 10% California State investment tax credit – no size limit, no end date
- Competitive CHP Pricing – capital costs reductions increased by an additional 10% to reflect learning and market competition
- Increase in market participation due to removal of barriers and risk by an additional 2-7%
- $50/kW-year T&D capacity deferral payment for CHP less than 20 MW

# Treatment of Risk Perception in the Model – Assumptions for All Cases

| Maximum Market Parcipation Rates | 50-500 kW | 500kW-1,000kW | 1-5 MW | 5-20 MW | >20 MW |
|---|---|---|---|---|---|
| Base Case | 50% | 60% | 70% | 80% | 80% |
| Medium Case | 60% | 69% | 77% | 85% | 85% |
| High Case | 65% | 70% | 79% | 90% | 90% |

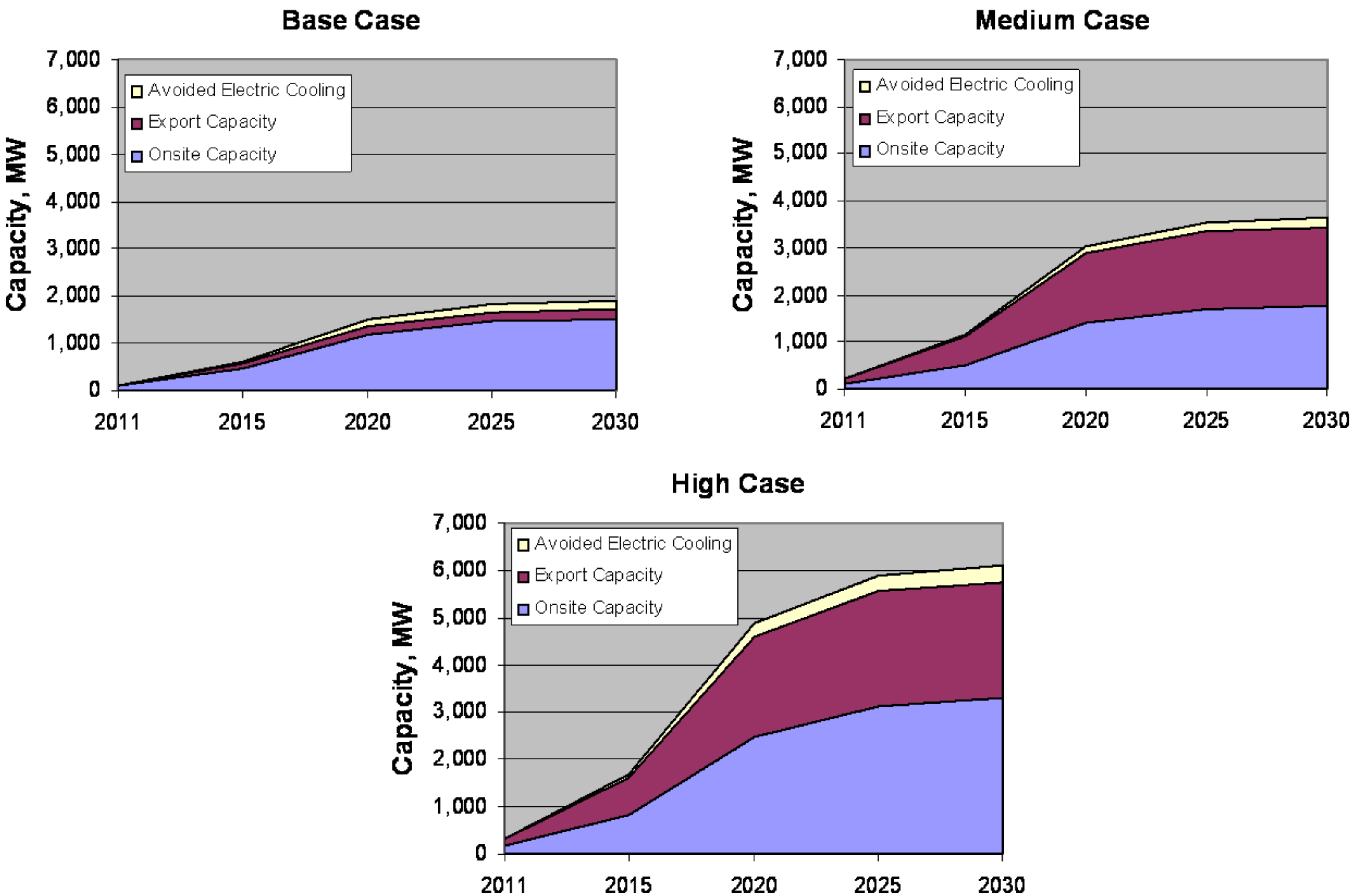
- Market participation in each size bin is restricted to reflect the effects of customers not considering CHP or being unable to use CHP for reasons of perceived risk such as: lack of financing, business instability, specific site restrictions, and other factors
- As the market increases, the maximum market participation factors are raised proportionally with the increase in market to reflect the better business environment and the greater willingness to participate

# Market Results:
# Cumulative New CHP Market Penetration

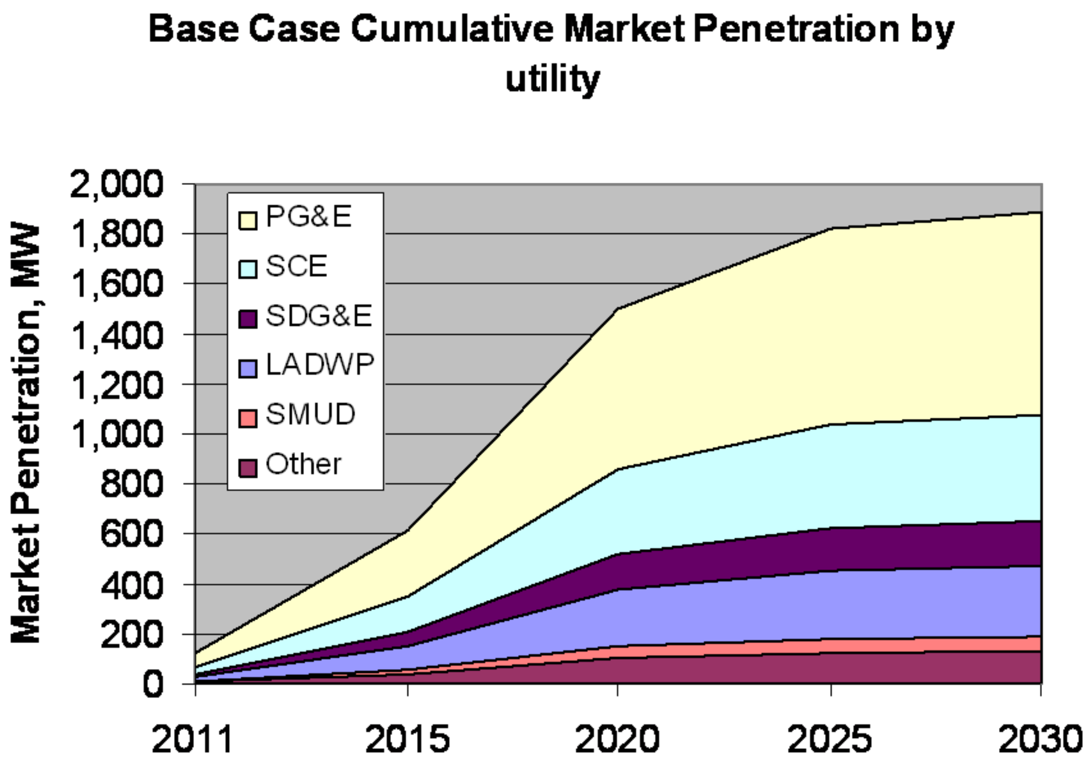



| Scenario | Cumulative New CHP Market Penetration, MW | | | | |
|---|---|---|---|---|---|
| | 2011 | 2015 | 2020 | 2025 | 2030 |
| Base Case | 123 | 617 | 1,499 | 1,817 | 1,888 |
| Medium Case | 233 | 1,165 | 3,013 | 3,533 | 3,629 |
| High Case | 340 | 1,700 | 4,865 | 5,894 | 6,108 |

# Cumulative Market Penetration by Type and Scenario



# Base Case Cumulative Market Penetration by Utility




- PG&E – 43%
- SCE – 22%
- LADWP – 15%
- SDG&E – 10%
- SMUD – 3%
- Other – 7%

# Small vs. Large CHP

| Scenario | Base | | Medium | | High | |
|---|---|---|---|---|---|---|
| Size | < 20 MW | > 20 MW | < 20 MW | > 20 MW | < 20 MW | > 20 MW |
| Onsite | 1,269 | 246 | 1,519 | 263 | 2,901 | 388 |
| Avoided AC | 130 | 30 | 155 | 32 | 316 | 45 |
| Export | 91 | 122 | 93 | 1,568 | 295 | 2,162 |
| Total | 1,489 | 399 | 1,766 | 1,863 | 3,513 | 2,595 |

- Small CHP Market
  - Primarily onsite market
  - More commercial applications with cooling
  - Incentive factors
    - SGIP
    - Retail price changes
    - Cost and performance improvements
    - Investment tax credit, T&D support

- Large CHP Market
  - Primarily export market
  - Mostly large process industries
  - Incentive factors
    - Export pricing
    - Removal of market uncertainty
    - Investment tax credit

# GHG Emissions Savings Estimation

CHP Electricity Generated Used On-site, kWh

+

CHP Cooling Avoided Air Conditioning, kWh

+

CHP Electricity Generated Exported to Grid, kWh

Line Losses

Avoided Grid Electric Generation

Electric $CO_2e$ Emissions
ARB Scoping Plan
Generation 963.4 lb/MWh
Line Losses 7.8%

+

CHP Avoided Boiler Fuel $10^6$Btu

-

CHP Fuel Use $10^6$Btu

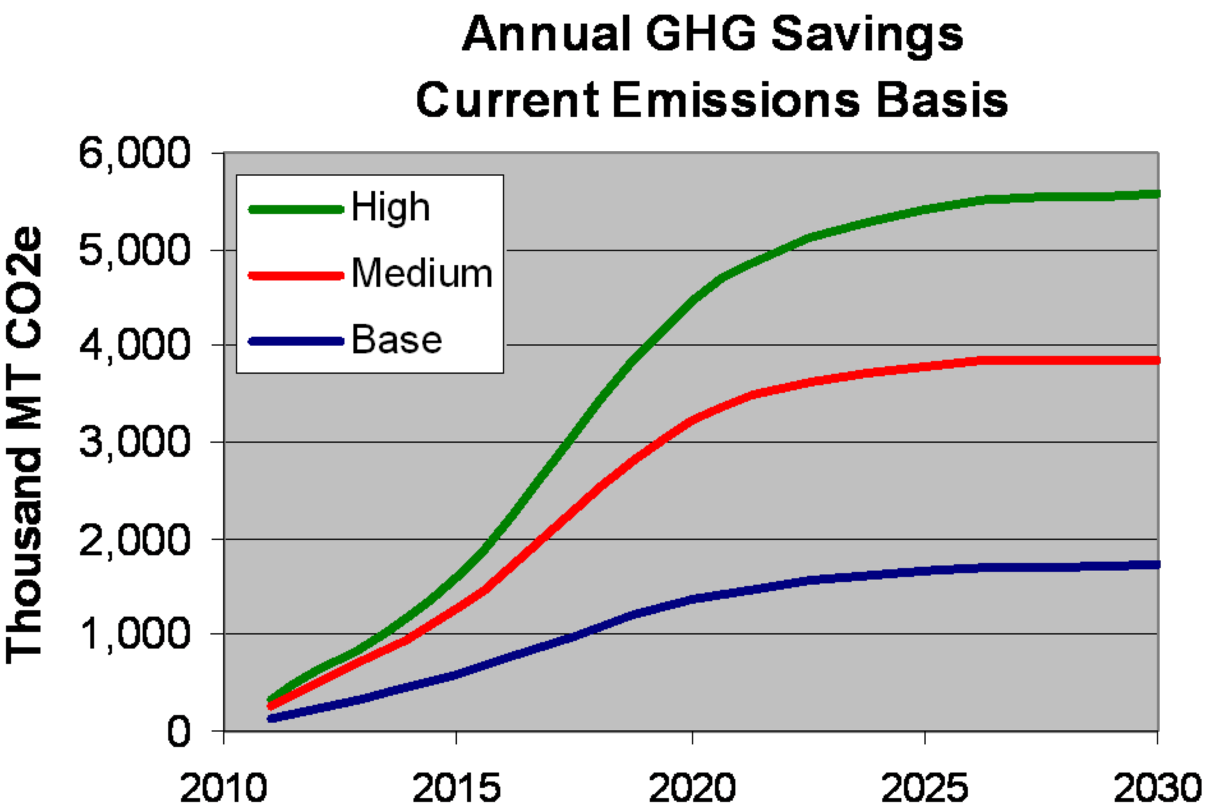
Incremental Fuel Use by CHP Technology

EG x (HR – TUF x AT / BE)

EG = Electricity generated kWh
HR = Heat Rate Btu/kWh
TUF = Thermal Utilization Factor
AT = Available Thermal Energy, Btu/kWh
BE = Boiler Efficiency

Natural Gas
$CO_2e$ Emissions
117 lbs/$10^6$Btu

# GHG Savings – Current Emissions Basis

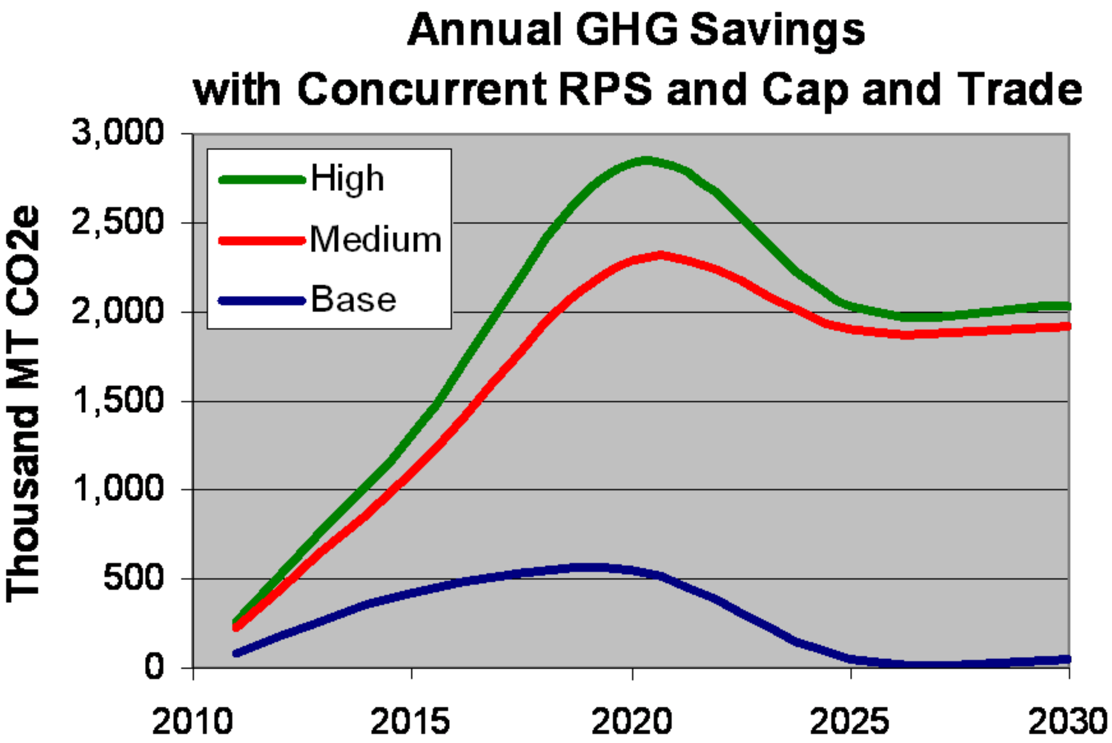



ARB Scoping Plan Avoided Electric Emissions Assumptions

| | |
|---|---|
| Emissions Generation Basis, lb/Mwh | 963.4 |
| Line Losses, % | 7.80% |
| Emissions Delivered Bases, lb/MWh | 1044.9 |

- Avoided electric sector and boiler emissions based on ARB Scoping Plan assumptions
- Avoided annual GHG emissions range from 1.4-4.5 million MT in 2020, 1.7-5.6 million MT by 2030

# GHG Savings – Competing with RPS and Cap and Trade Changes in Emissions Intensity




- RPS and Cap and Trade impact CHP savings over time
- Onsite CHP reduces electric capacity needs thereby reducing the effective savings by the RPS percentage
- Export CHP is figured into utility capacity so emissions impacts are not reduced

ARB Scoping Plan Avoided Electric Emissions Assumptions

| | |
|---|---|
| Emissions Generation Basis, lb/Mwh | 963.4 |
| Line Losses, % | 7.80% |
| Emissions Delivered Bases, lb/MWh | 1044.9 |

Reduced by RPS Goals

# Conclusions: Market Penetration Lower than 2009 Study

- Economic slowdown reduced technical market potential
- CHP technology capital costs have increased due to higher equipment and installation costs
- Export pricing for systems less than 20 MW is lower than assumed in 2009
- Spark spread is somewhat more favorable but this is offset by effects of Cap and Trade
- SGIP benefits are limited by the program's current expiration date of 2016

# Conclusions: Policy Measures Considered to Increase Market Penetration

- Extending the SGIP deadline and reducing the phased reduction of benefits
- State business investment tax credit for CHP
- Reimbursement of GHG allowance costs for incremental CHP fuel consumption
- CHP rate reform with respect to NBCs and multiple demand charges
- Credit for T&D support for CHP systems on the distribution system
- Contracting for new CHP export at long run marginal avoided costs

# Conclusions: Large and Small Capacity Market Issues

- Small capacity markets respond to SGIP, T&D deferral payments, electric rate increases due to RPS, and system cost reductions over time
- Large capacity markets respond primarily to export price
- All markets benefit from investment tax credits and the effect that RPS will have on electric price
- Small markets, primarily, are hurt by costs associated with Cap and Trade – large export markets have a mechanism to recover those costs

# Conclusions: Export Market is Highly Uncertain

- Model showed range of possible new export market penetration depending on the assumed export price – 213-2,457 MW
- Prices approaching the full long run marginal cost of power are needed for significant penetration of new large CHP export projects – not short run avoided cost
- Smaller, AB 1613 eligible projects, have higher costs making it difficult to compete even with the utility long run marginal cost – ICF model lacks detail to include analysis of 10% locational adder
- Model assumptions set price and determine quantity of market penetration – QF Settlement and Long Term Procurement Planning (LTPP) determines quantity and market sets price
- 3,000 MW procurement targets under the QF Settlement could be fully subscribed by existing CHP – after 3,000 MW target is met, new CHP procurement targets will be determined in LTPP, large export potential of 2,162 MW included in the high case is highly dependent on generator ability to secure long term contracts to reduce investment risk

# Conclusions: CHP Benefit to Customers and to California Environmental Goals

- GHG emissions savings
  - Contribution to total GHG emissions smaller than scoping plan target
  - Concurrent carbon reduction programs will reduce the marginal GHG benefits over time
  - The focus should be on the cost effectiveness of GHG reduction (CHP is cheaper than some renewable alternatives)
- CHP will save customers energy costs
  - $740 million/year in the Base Case by 2030
  - $2.9 billion/year in the High Case by 2030