West Coast Investor Meetings

August 25 -27, 2015

CLEAN MODERN EFFICIENT FLEXIBLE POWER GENERATION

Safe Harbor Statement

Forward-Looking Statements

The information contained in this presentation includes certain estimates, projections and other forward-looking information that reflect Calpine's current views with respect to future events and financial performance. These estimates, projections and other forward-looking information are based on assumptions that Calpine believes, as of the date hereof, are reasonable. Inevitably, there will be differences between such estimates and actual results, and those differences may be material.

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All such estimates, projections and forward-looking information speak only as of the date hereof. Calpine undertakes no duty to update or revise the information contained herein other than as required by law.

You are cautioned not to place undue reliance on the estimates, projections and other forward-looking information in this presentation as they are based on current expectations and general assumptions and are subject to various risks, uncertainties and other factors, including those set forth in Calpine's Quarterly Reports on Form 10Q for the three months ended March 31 and June 30, 2015, its Annual Report on Form 10-K for the year ended December 31, 2014 and in other documents that Calpine files with the SEC. Many of these risks, uncertainties and other factors are beyond Calpine's control and may cause actual results to differ materially from the views, beliefs and estimates expressed herein. Calpine's reports and other information filed with the SEC, including the risk factors identified in its Annual Report on Form 10-K for the year ended December 31, 2014, can be found on the SEC's website at www.sec.gov and on Calpine's website at www.calpine.com.

Reconciliation to U.S. GAAP Financial Information

The following presentation includes certain "non-GAAP financial measures" as defined in Regulation G under the Securities Exchange Act of 1934, as amended. Schedules are included herein that reconcile the non-GAAP financial measures included in the following presentation to the most directly comparable financial measures calculated and presented in accordance with U.S. GAAP.

Proven & Experienced Management Team

Jack Fusco
Executive Chairman

- CPN tenure: 7 years
- Power industry experience: 30 years

Thad Hill
President, CEO

- CPN tenure: 7 years
- Power industry experience: 20 years

Thad Miller
EVP, Chief Legal Officer

- CPN tenure: 7 years
- Power industry experience: 25 years

Zamir Rauf
EVP, Chief Financial Officer

- CPN tenure: 15 years
- Power industry experience: 17 years

Trey Griggs
EVP, Chief Commercial Officer

- CPN tenure: <1 year
- Energy sector experience: 15 years

Well-tenured team maintaining focus on delivering operational excellence and creating shareholder value

Calpine Generating Power

Strategically positioned within U.S. power industry value chain

Fuel Supply

Transportation

Transmission & Distribution

Retail[1]

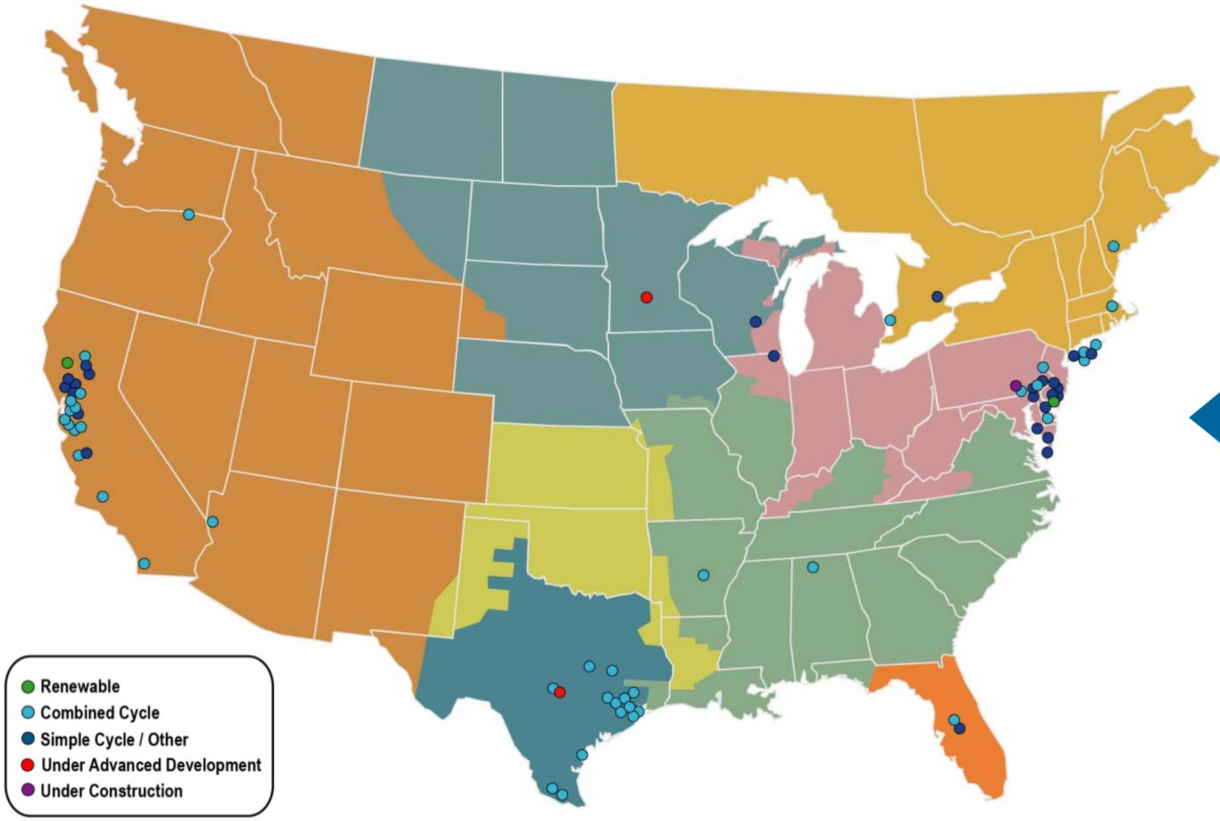
Power Generation

Calpine (NYSE: CPN)

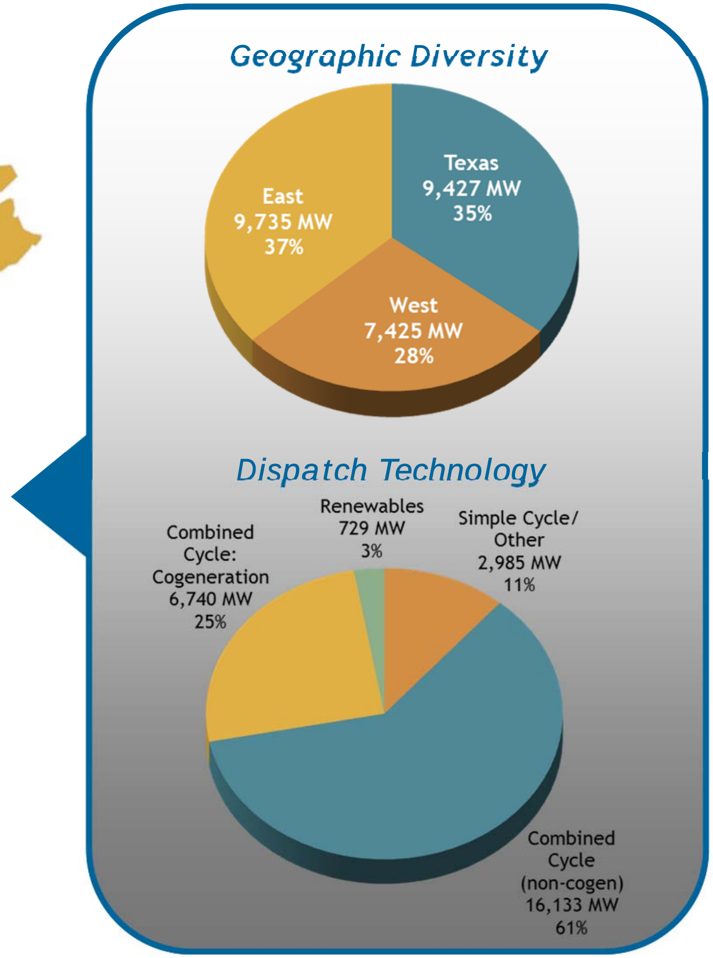
- ~2,000 employees
- ~27,000 MW generation capacity
- 83 power plants

[1] Acquisition of Champion Energy expected to close by 4Q15.

National Portfolio of Approximately 27,000 MW



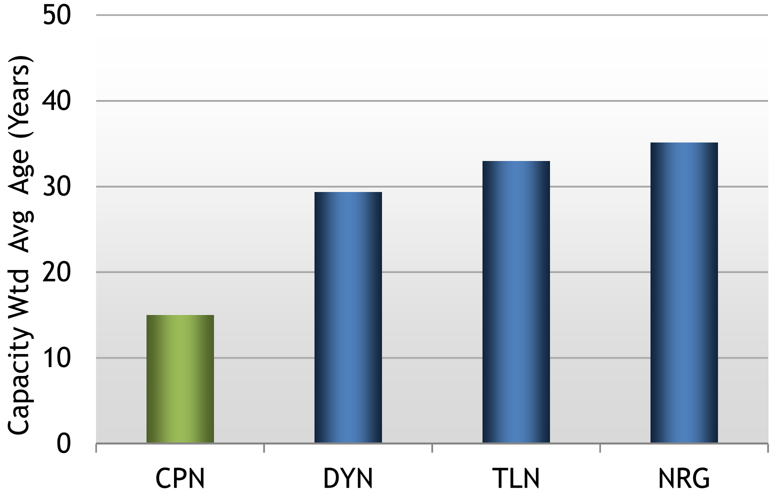
As of 07/30/2015



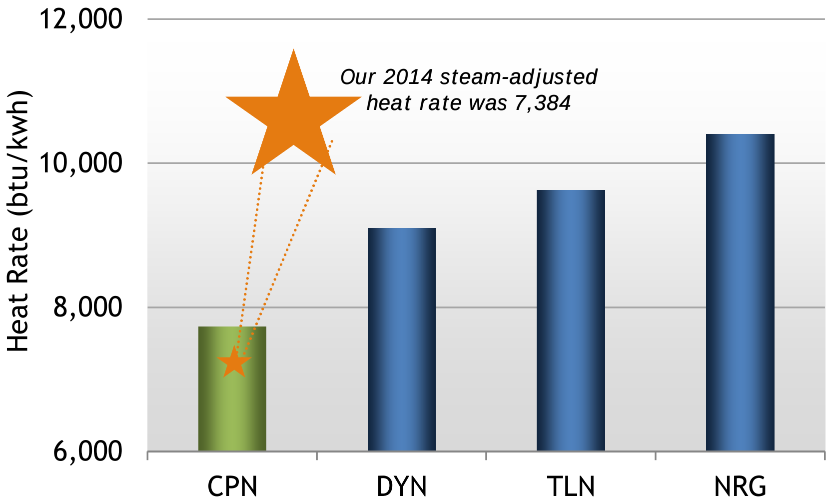
- Geographically diversified portfolio: Scale in three most competitive power markets in America
- Largest operator of combined heat and power (cogeneration) technology in America
- Largest geothermal power producer in America
- Featuring one of smallest environmental footprints in America's power generation sector

Nation's Largest Baseload Renewable, Natural Gas and Cogeneration Power Provider

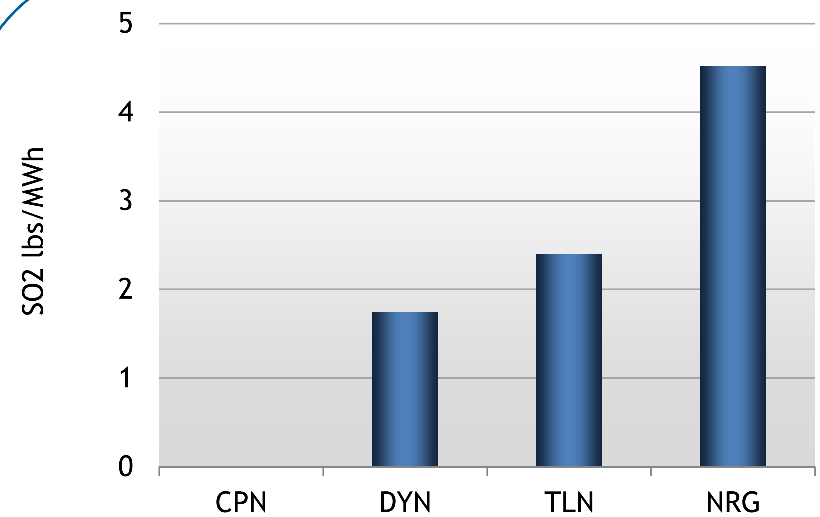
Modern

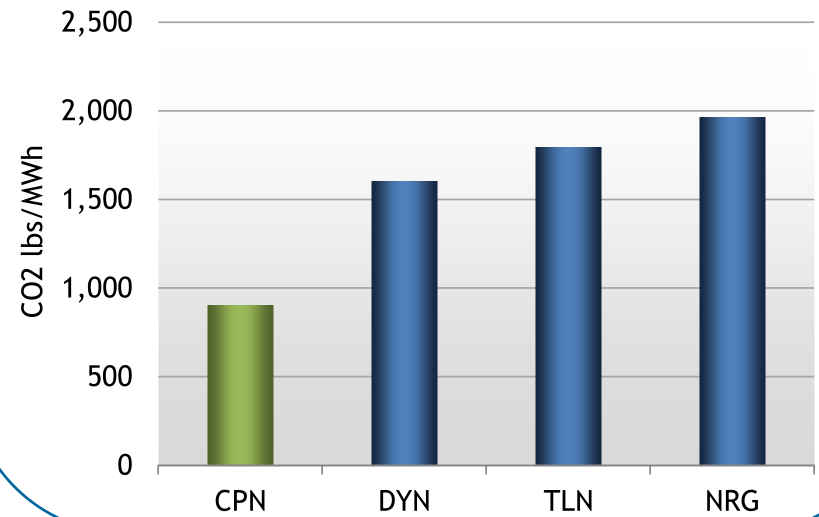


Efficient



Clean





Source: Calpine, Energy Velocity (2014). Figures adjusted to incorporate announced/completed M&A activity as though it were effective as of 1/1/14. CPN steam-adjusted heat rate excludes peakers. TLN does not reflect potential divestitures required to occur within 12 months of formation.

Calpine Investment Thesis

Premier power generation company

- Strong leadership bench
- Best-in-class operations
- Diverse regional strategic landscape
- Competitive wholesale power markets

Secular trends favor natural gas-fired generation

- Increasingly stringent environmental regulations
- Sustained low natural gas prices
- Focus on grid reliability: pay-for-performance initiatives
- Need for flexible capacity to integrate intermittent renewables

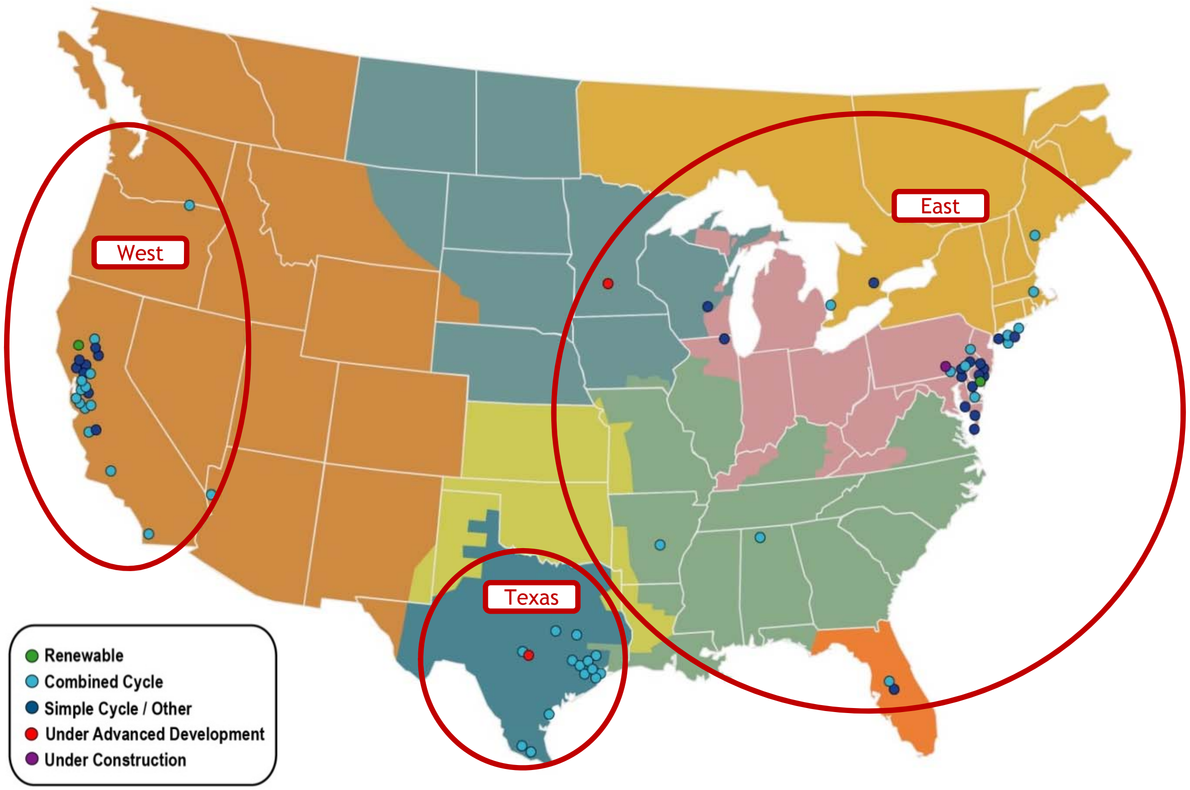
Cash-based capital allocation philosophy

- Monetizing assets through sale or contracts
- Pursuing financially disciplined growth
- Committed to returning capital to shareholders
- Strong liquidity and minimal near-term debt maturities

Calpine represents an attractive opportunity to gain exposure to the combined-cycle gas turbine recovery at a substantial discount to replacement cost

REGIONAL OBSERVATIONS

Consistent Focus on Core Competitive Markets



As of 7/30/2015

West

- *Strategic Priority:*
  Asset management and regulatory engagement given CA renewable integration challenges
- *Near-Term Opportunities:*
  - Recontracting existing plants (gas and geothermal)

Texas

- *Strategic Priority:*
  Capitalize on volatility and tightening market fundamentals while extending customer channels
- *Near-Term Opportunities:*
  - Public power
  - Retail: Recently announced acquisition of Champion Energy
  - Industrial/cogen build-out

East

- *Strategic Priority:*
  Capitalize on unprecedented transition from coal-dominated to gas-centric market
- *Near-Term Opportunities:*
  - PJM low-$/kW merchant expansions
  - MISO contracted expansion (Mankato)
  - Monetize remaining SE plants (sale or contract)
  - Redoubled origination efforts

Calpine Guiding Principles

- Operational excellence: Be the industry's premier operating company
- Focus on cash: All investments evaluated on Adj. FCF/Share basis (levered returns to equity)
- Investing in growth *and* returning capital to shareholders
- Portfolio optimization: Redeploy capital to capture highest returns
- Advocacy: Environmentally responsible power generation and competitive wholesale power markets

Favorably Positioned to Respond to Secular Trends

($ millions)

Environmental Trends

- Increasingly stringent environmental regulations (activist EPA)
- More renewables = Higher value for flexibility, lower for baseload

EPA Rule	Final Rule	Effective
CSAPR	2012	2015
MATS	2012	2015
Regional Haze (TX)	2015[1]	2018 - 2020
Ozone NAAQS	2015	2019+
Clean Power Plan	2015	2022

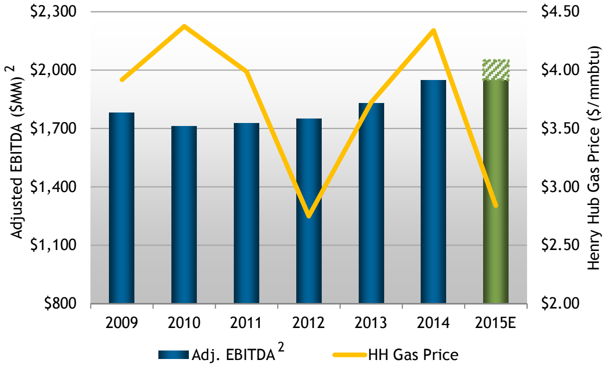
Reliability Initiatives

- Increased focus on system reliability during scarcity events

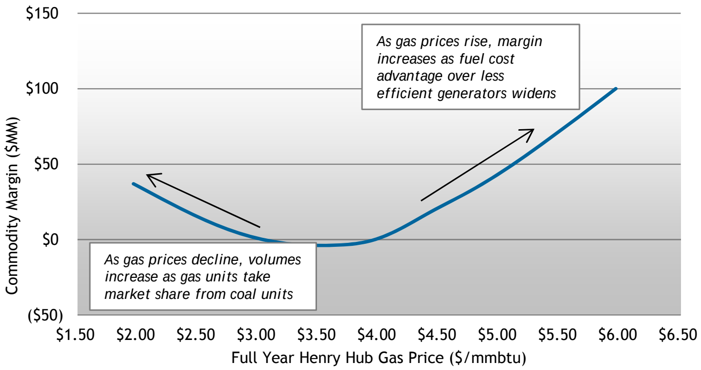
Market	Product	Eff. Date
PJM	Capacity Performance	May 2016 → May 2018
ISO-NE	Performance Incentives	May 2018
ERCOT	$9,000/MWh SWOC	Jun 2015
All	Price Formation	Ongoing

Shale Gas Economics

Stable Financial Performance Despite Gas Price Volatility



Resilient in Low-Gas Price Setting



Notes: Graph reflects modeled impacts of changes in gas price on 2015 unhedged portfolio. Based on Calpine analysis using forward curves as of 7/18/14. Reflects observed forward market relationships between natural gas prices, heat rates and basis.

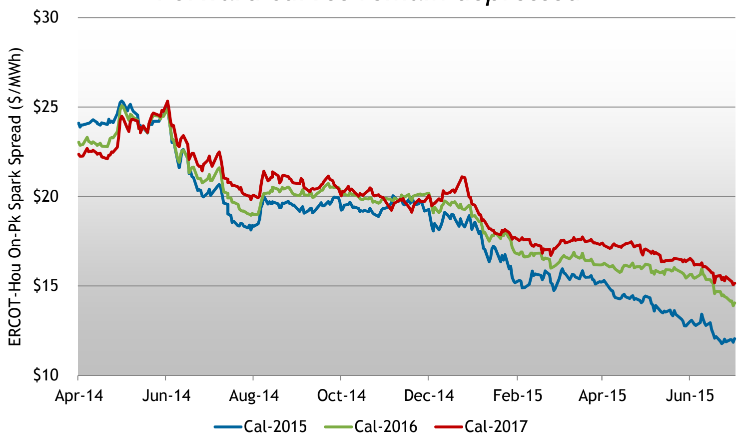
Secular trends favoring reliable, dispatchable generation

[1] Anticipated approval for TX FIP. [2] A non-GAAP financial measure. Reconciliations of Adj. EBITDA and Adj. FCF to Net Income (Loss), the most comparable U.S. GAAP measure, are available in the appendix. 2015E as of 7/30/15.

Tale of Two Markets: Energy-Only (TX) vs. Capacity (PJM)

Texas: Low Spark Spreads Challenging; Supply Rationalization Necessary

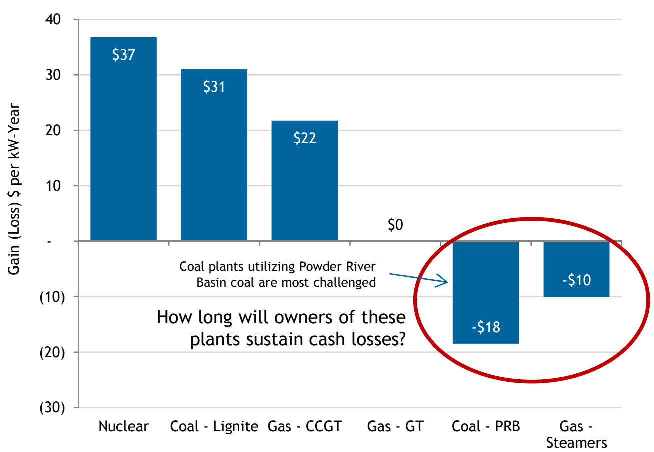
Forward curves remain depressed



Source: Broker quotes, Calpine.

~25% of ERCOT capacity likely not covering fixed costs

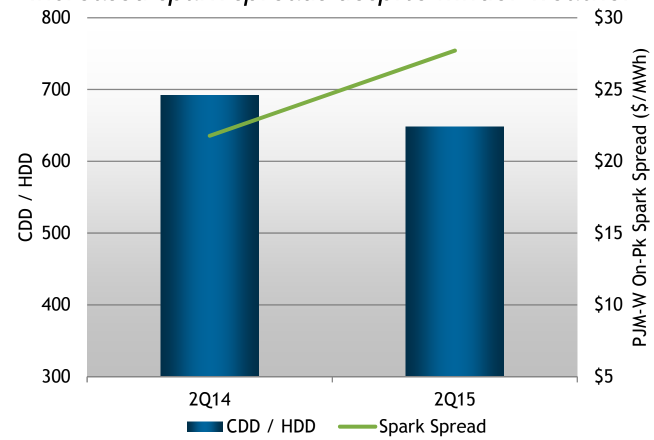
Illustrative ERCOT Supply Stack Economics[1]



Source: Energy Velocity, Calpine. Based upon ERCOT-North 2016 forward prices as of 7/17/15.

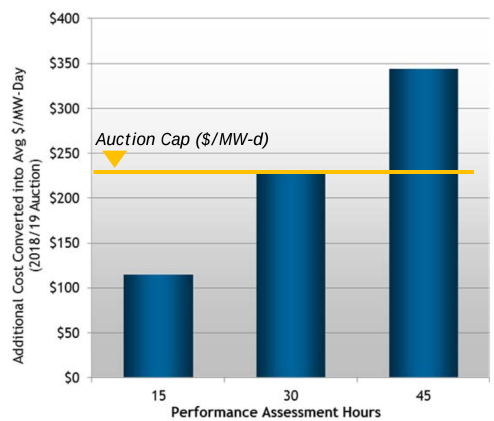
East: Energy Markets Intact, Capacity Performance on Horizon

Increased spark spreads despite milder weather



Source: NOAA, Broker quotes, Calpine.

Capacity Performance: How Will Bids Capture Risk of "Giving it All Back" in Two Days?



Plant Type	Avg. Annual Outage Hours
Nuclear	158
CCGT	228
CT	517
Steam	771
Diesel	1,226

Source: PJM, Calpine. Average annual outage hours based upon PJM 2014 State of the Market report. Steam includes coal, oil and gas steam turbines.

California's Reliance on Renewables Drives Value for Flexible Generation

Increasing Market Volatility Driven by Reliance on Renewables…

Recent Example: Unexpected Load + Insufficient Renewables → Pricing Volatility

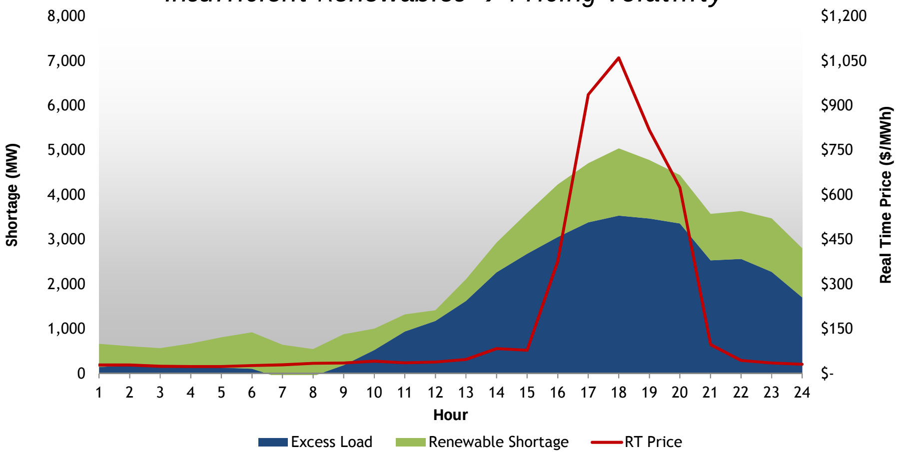
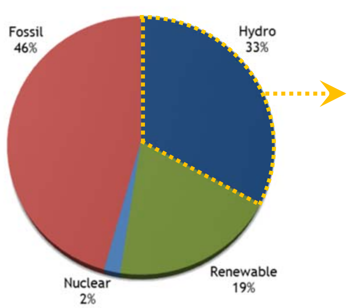
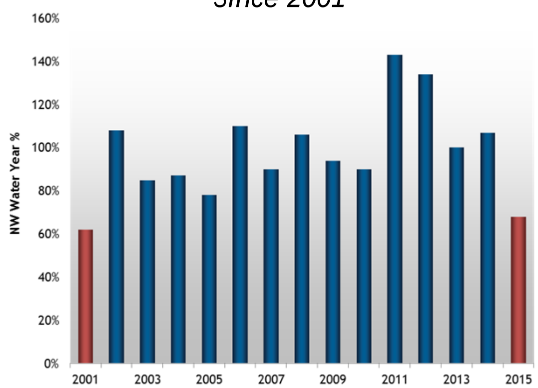


Chart reflects hourly load in excess of projections, renewables below projections and real-time prices on 6/8/15. Source: CAISO.

Hydro a Significant Component of NW[1] Generation Supply



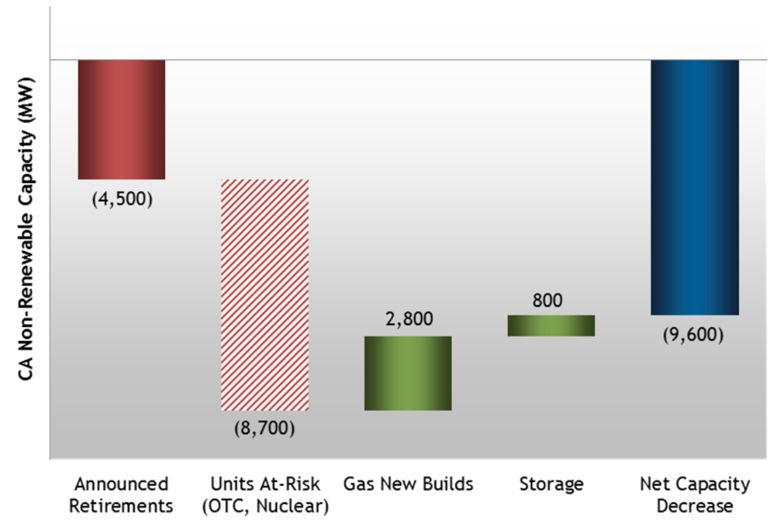
Lowest Northwest Hydro Since 2001



Sources: Energy Velocity, NOAA.
[1] Includes California, Oregon, Washington.

…Demonstrates Need for Flexible Generation to Ensure Grid Stability

Near-Term Retirements of Non-Renewable Resources Not Being Replaced in Kind (2016 – 2021)

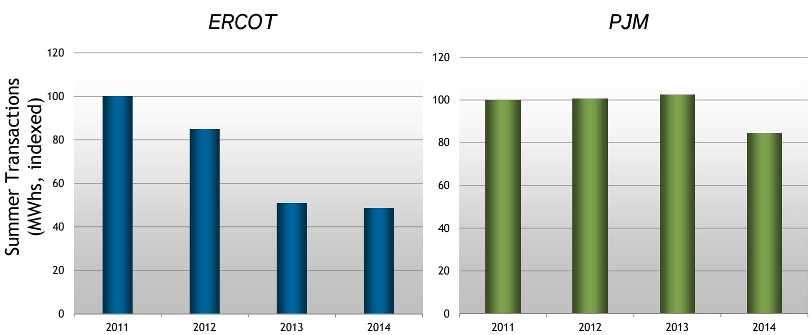


Current dynamics highlight the value of flexible generation resources

Source: Energy Velocity, SNL, NERC, CPUC, CEC, Calpine. New builds exclude plants without signed contracts. Storage represents capacity to be applied toward Planning Reserve Margin under existing CPUC mandate.

Origination Efforts: Getting Closer to Our Customers

Diminished liquidity in some markets driving need for more direct customer contact[1]



Note: Represents ICE transactions only (excludes over-the-counter).

Guadalupe Peaking Energy Center

- 418 MW peaking plant to be brought online between Jun 2017 - Jun 2019 at Calpine election
- Structured to meet customer's requirements while timing construction with appropriate market signals

Expanding customer relationships

End-Use Customers:

- Direct C&I sales (~130 MW)
- Load-following products (~850 MW)
- Cogen contracts (~1,000 MW + Steam)

California Community Choice Aggregators:

- Marin Clean Energy: Delta, Northern CA power fleet, Geysers
- Sonoma Clean Power: Geysers

Texas Public Power Efforts:

Customer	Contract Capacity (MW, Approx.)	Tenor (Yrs.)	As of
• City of San Marcos	18	6	2015
• Pedernales Electric Co-Op	70	2	2016
• Guadalupe Valley Co-Op	270	1	2016
• Brazos Electric Co-Op	300	3	2016
• Pedernales Electric Co-Op	140	3	2017
• Guadalupe Valley Co-Op	270	2	2017
• Guadalupe Peaking Energy Center	- Guadalupe Valley Co-Op to purchase 50% equity interest in new 418 MW peaking plant		

[1] Source: ICE, Calpine. Summer on-peak transactions shown. Volumes are presented by year in which they were transacted and reflect only the contract period to be delivered during the summer of the same calendar year. All volumes include only quarterly, monthly and monthly strip contracts to be delivered during May through September. Full calendar year strips (Jan-Dec) have been excluded. Over-the-counter transactions have been excluded.

Expanding Customer Channels Through Acquisition of Well-Established Retail Sales Platform

CALPINE

Transaction Summary

- \$240 million[1] acquisition of nation's largest independent retail electric provider
- Purchased at **~4-5x initial Adjusted EBITDA[2]**; Immediately accretive to Adj. FCF[2] Per Share
- Expected to close by 4Q15

Strategic Rationale

- Consistent with previously announced initiatives to get "closer to customers"
  - Essential in an era of declining wholesale power market liquidity
- Ideal platform to add sizeable retail organization
  - Experienced team with track record for growth
  - Significant geographic overlap with Calpine wholesale fleet
  - Customer service commitment mirrors Calpine focus on operational excellence

Extending customer reach through accretive acquisition

CHAMPION ENERGY SERVICES®

Source: Champion Energy.

- ~22 million MWh of customer load served annually[3]
- Currently operating in ERCOT, PJM, MISO, NYISO and ISO-NE; New coverage areas to come
- Primarily Commercial & Industrial customer base (~90% of load in 2014): ~19,000 C&I customers, or ~2 million residential customer equivalents[4]
- Award-winning customer service practices, driving strong retention rates

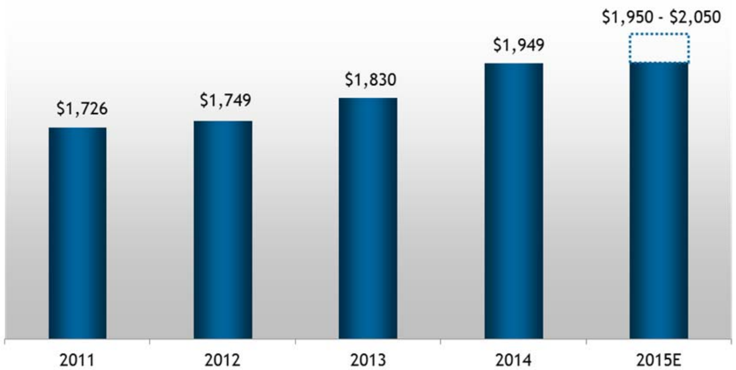
[1] Subject to working capital adjustments. [2] A non-GAAP financial measure. Reconciliations of Adj. EBITDA and Adj. FCF to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix. [3] Estimated for 2015. [4] Industry standard conversion assumes 10 MWh of annual electricity usage per residential customer.

FINANCIAL OVERVIEW & CAPITAL ALLOCATION

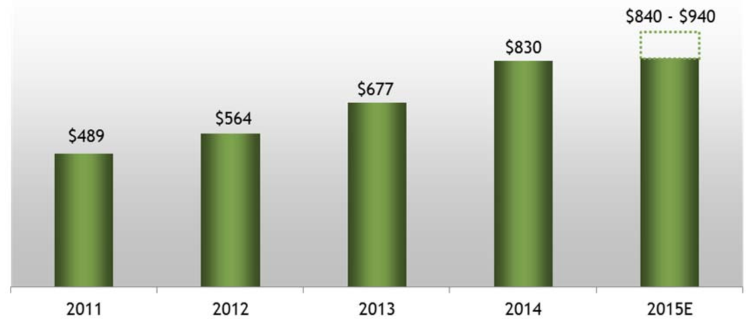
Delivering Strong Financial Performance

($ millions)

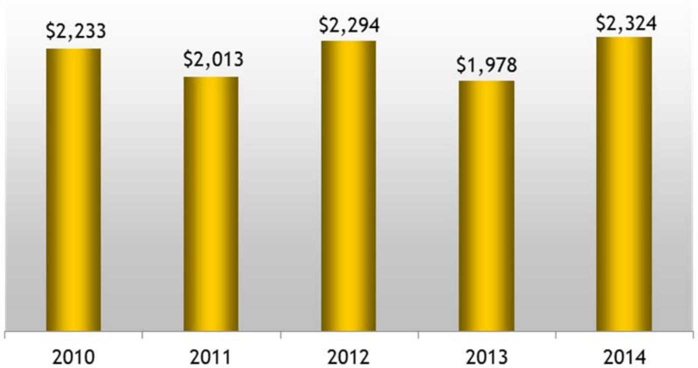
Stable Adjusted EBITDA[1]



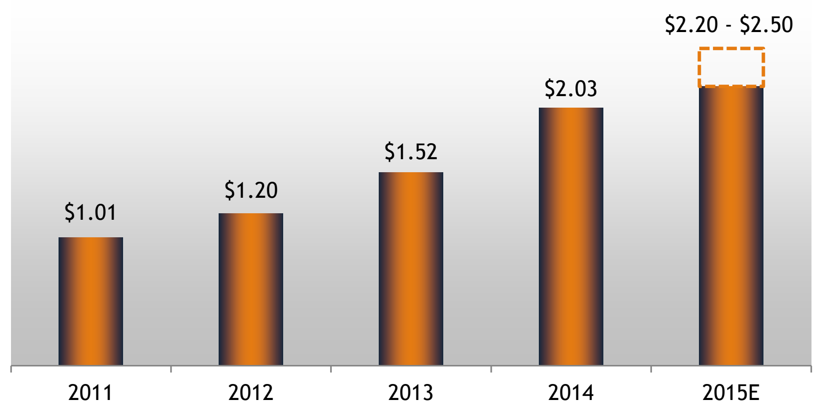
Solid Adjusted FCF[1]



Ample Liquidity



Strong Adjusted FCF[1] Per Share



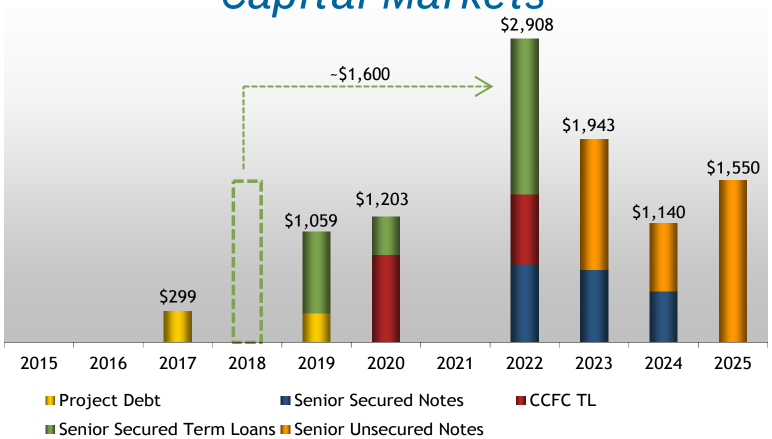
Positioned to respond to favorable secular and fundamental trends

[1] A non-GAAP financial measure. Reconciliations of Adjusted EBITDA and Adjusted Recurring Free Cash Flow to Net Income, the most comparable U.S. GAAP measure, are included in the appendix. 2015E based on guidance as presented on 07/30/2015.

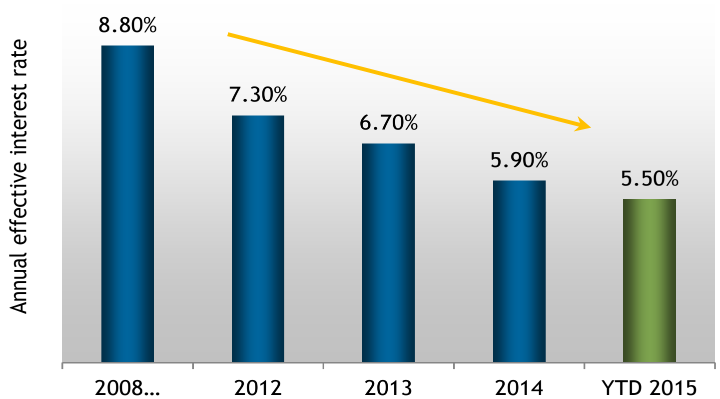
Opportunistic Refinancing & De-Levering

($ millions)

Continuing to Opportunistically Access Capital Markets[1]



Reducing Interest Expense



Recent transaction

- Refinanced ~$1.6 billion 2018 First Lien Term Loan with equivalent due 2022
  - Reduced annual interest expense
  - Extended maturity profile by four years

Future opportunities

- Opportunity to pay down ~$700 million of high cost debt (7.875% Notes due 2023)
  - Exercise two remaining calls at 103 ($120 million each, 4Q15 + 4Q16)
  - Redeem remaining ~$450M (callable at ~104 as of 1Q17)
- Refinancing / Repricing opportunities
  - Steamboat
  - Russell City
  - 2019 & 2020 Term Loans

Value creation through effective balance sheet management and focus on Adjusted Free Cash Flow[2]

[1] The debt maturity schedule shown here is not prepared on a U.S. GAAP basis and does not conform to the debt maturity schedule presented in Calpine's Form 10-K. (Refer to the Form 10-K for further information regarding U.S. GAAP-basis debt maturities). Assumptions used in debt maturity charts shown here are as follows: (i) excludes letter of credit facilities; (ii) maturity balances assume cash sweeps; and (iii) all other debt maturities are paid from operating cash flows at the project level. Project debt in 2019 represents projected balance for OMEC. Put price in the PPA approximates the projected debt balance.

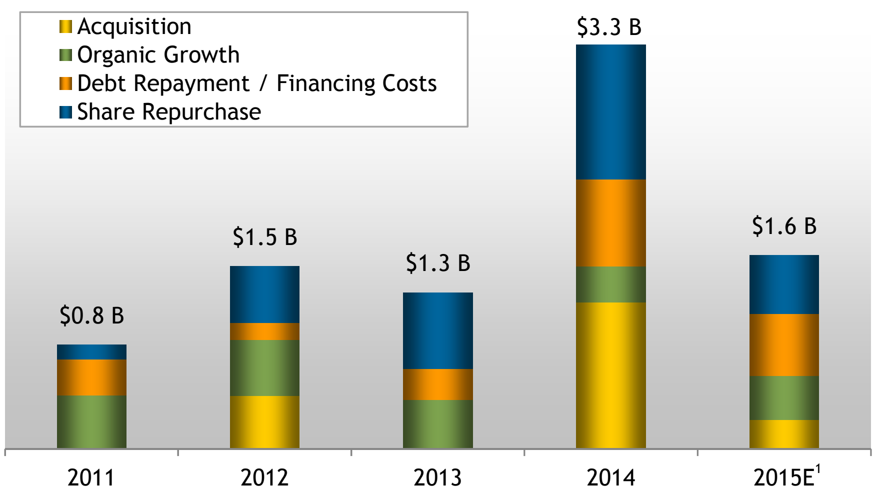
[2] A non-GAAP financial measure. Reconciliations of Adj. EBITDA and Adj. FCF to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.

Cash-Based Capital Allocation Philosophy in Action

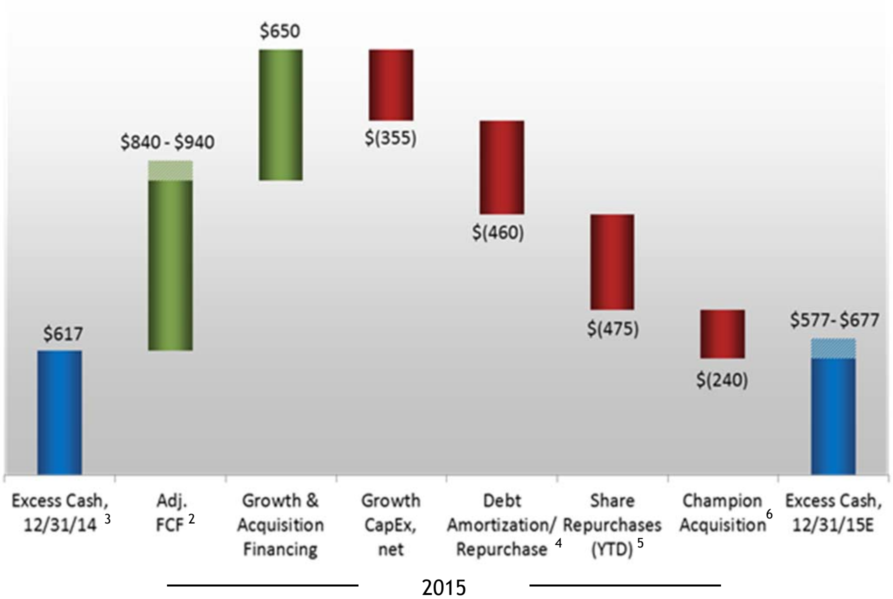
CALPINE

($ millions, unless otherwise noted)

Demonstrating Disciplined and Balanced Approach



Maintaining Strong Excess Cash and Capital Allocation Flexibility

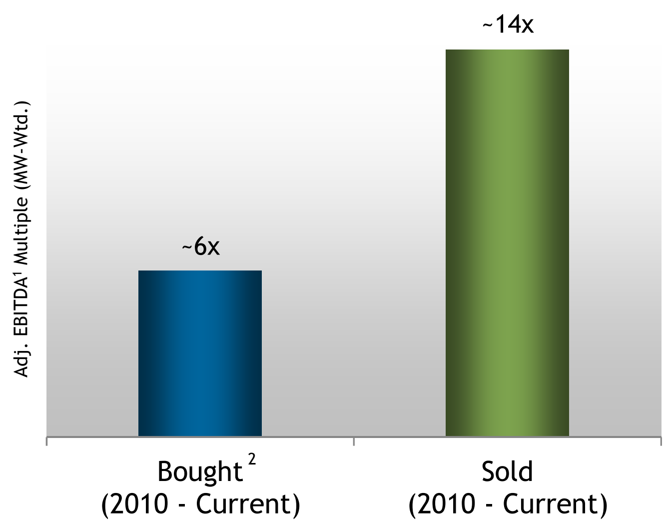


[1] As of 7/30/15 and includes estimated / announced 2015 growth capital expenditures, debt amortizations/repurchases, and YTD share repurchases.
[2] A non-GAAP financial measure. Reconciliations of Adjusted EBITDA and Adjusted Free Cash Flow to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.
[3] Assumes $1 billion minimum liquidity and $100 million minimum balance of cash on hand.
[4] Includes scheduled amortization of approximately $193 million, the repurchase of approximately $147 million of our 2023 First Lien Notes in February 2015 and expected exercise of the 10% call feature on our 2023 First Lien Notes for approximately $120 million.
[5] As of 07/29/15.
[6] Subject to working capital adjustments.

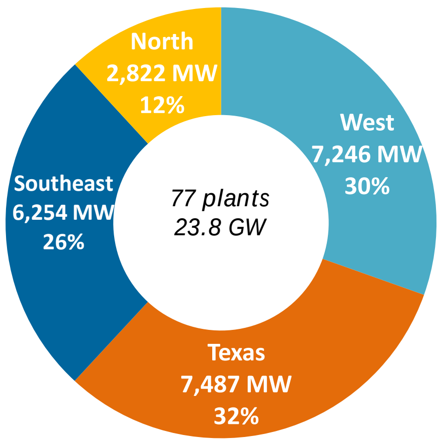
Track Record for Transformative Redeployment of Capital

Strategic Repositioning

Accretive Allocation of Capital in Strategic Markets



2Q08:



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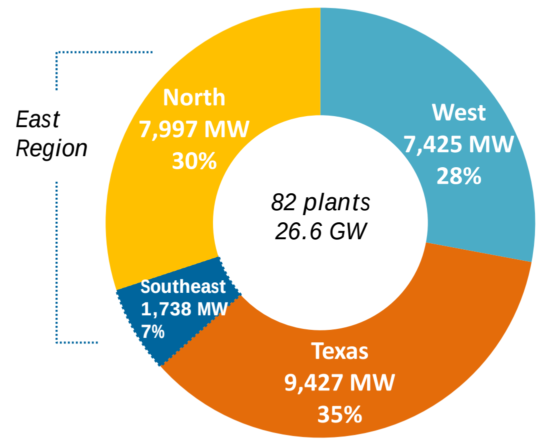
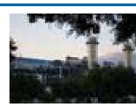


[1] A non-GAAP financial measure. Reconciliations of Adj. EBITDA and Adj. FCF to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.
[2] Does not include recently announced acquisition of Champion Energy.

Accretive M&A History:
Strategically Redeploying Capital into Core Regions

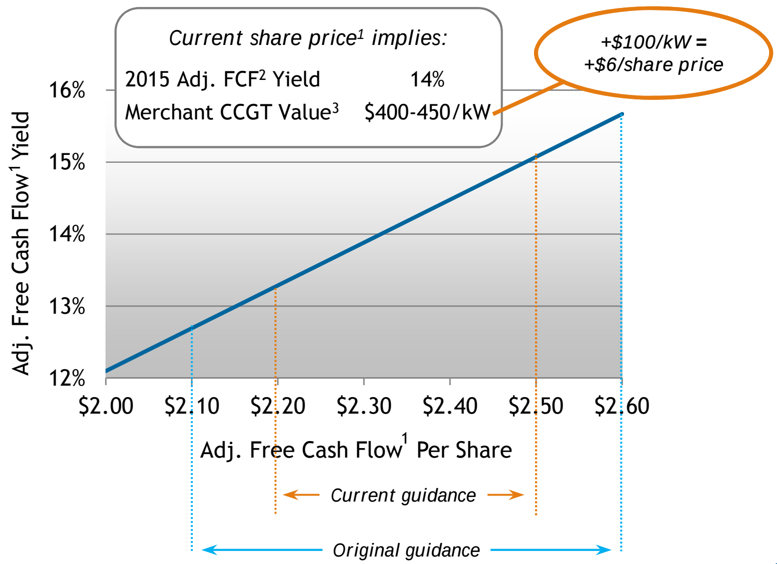
	Transaction		Description	Capital[1] ($MM)	Economics
$3.2B of Acquisitions:	Fore River Generating Station		• 4Q14: 809 MW combined-cycle power plant in constrained New England market	$530	*~6x Adj. EBITDA*
	Guadalupe Energy Center		• 1Q14: 1,050 MW combined-cycle power plant in attractive Texas market • Expansion optionality	$625	
	Bosque Energy Center		• 4Q12: 800 MW combined-cycle power plant in attractive Texas market	$432	
	Conectiv Portfolio		• 2Q10: ~4,500 MW natural gas-fired generation capacity in strategic Mid-Atlantic region • Imbedded development opportunities	$1,650	
$3.5B of Divestitures:	Osprey Energy Center		• 1Q17E[2]: 599 MW combined-cycle power plant in non-core market (Florida); Signed PPA through sale date	$166	*~14x Adj. EBITDA*
	Southeast “Six Pack”		• 2Q14: ~3,500 MW natural gas-fired generation capacity in non-core market (Southeast)	$1,570	
	Broad River Energy Center		• 4Q12: 847 MW peaking power plant in non-core market (South Carolina)	$427	
	Riverside Energy Center		• 4Q12: 603 MW combined-cycle power plant in non-core market (Wisconsin); near-dated contract expiry	$392	
	Freestone Energy Center		• 4Q10: Sale of 25% minority interest in 1,038 MW combined-cycle power plant in Texas	$215	
	Colorado Portfolio		• 2Q10: 931 MW natural gas-fired generation capacity in non-core market; near-dated contract expiry	$739	

[1] Reflects price at date of announcement, subject to closing adjustments.
[2] Pending regulatory approvals.

Why You Should Invest in Calpine Today

Attractive Entry Point, Given Favorable Future Drivers

Compelling Value Proposition…



…Supported by

Secular shift away from baseload generation

- Increasing environmental regulations
- Sustained low nat gas prices
- Influx of intermittent renewables → Need for integration and ramping support
- Regulatory emphasis on reliability: "Pay for Performance"

Four near-term drivers

1) Clean Power Plan
2) PJM Capacity Performance
3) Option to pay off high priced debt; Refi other debt
4) Announced growth: York 2

~$0.75

Adj. FCF[1] Per Share (2018 v 2016)[4]

Disciplined capital allocation + Active portfolio management: What's next

Monetize Yield	Potential monetization of contracted asset(s) to capitalize on yield frenzy
Return Capital	Share repurchases as ongoing part of capital allocation program
Manage Portfolio	Asset optimization, M&A, growth
Manage Balance Sheet	Option to pay down ~$700M of 7⅞ debt + Ongoing amortization and refinancing opportunities
Focus on Customers	New contracts + Leverage and grow Champion platform

Powerful Free Cash Flow Generator

See footnotes on slide 32 in appendix.

APPENDIX

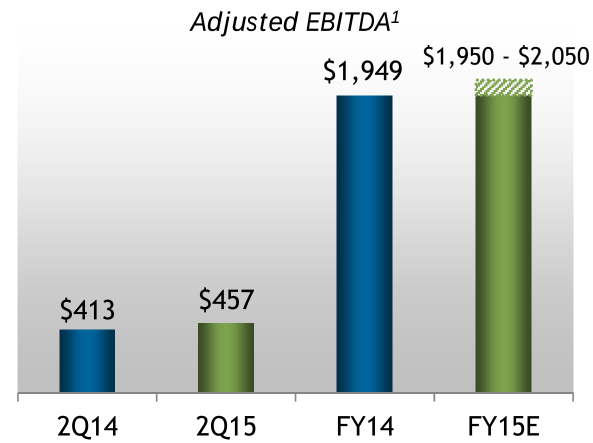
Delivering on All Fronts in 2015

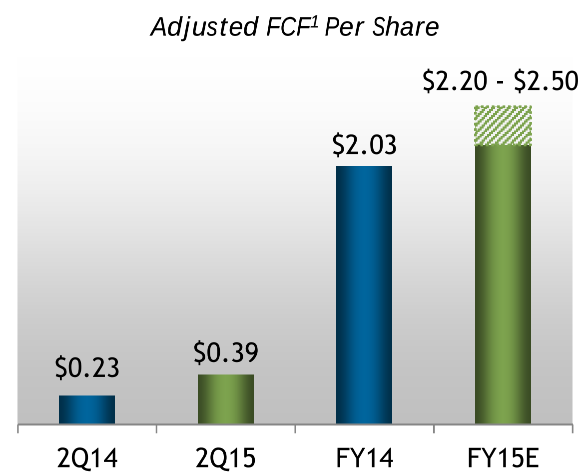
($ millions)

Recent Highlights

- Narrowed 2015 guidance while maintaining midpoint
  - Adjusted EBITDA[1]: $1.95 - $2.05 billion
  - Adjusted Free Cash Flow[1] Per Share: $2.20 - $2.50
- Outstanding operating and commercial performance
  - Record high 2Q generation volume: 28 million MWh
  - Top quartile safety performance + <2% FOF
  - Geysers 10-year 50 MW contract with SCE (2018)[2]
  - FERC approval of Osprey sale
- Active capital allocation
  - Announced acquisition of Champion Energy, a leading electric retailer
  - Achieved COD at Garrison; York 2 under construction
  - Repurchased $239 million of shares since 1Q15 call ($475 million YTD) [3]
- Refinanced $1.6 billion term loans, reducing interest rate and extending maturity

Strong Second Quarter Results; Narrowed Full Year Guidance





[1] A non-GAAP financial measure. Reconciliations of Adj. EBITDA and Adj. FCF to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.
[2] Pending CPUC approval.
[3] As of 07/29/15.

Selected Operating Statistics

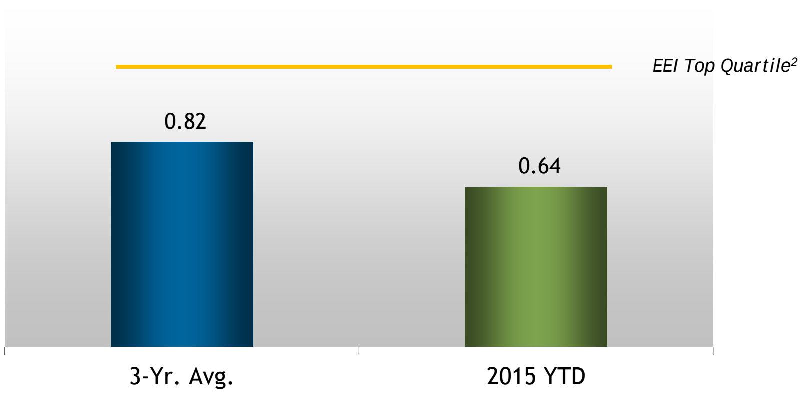
	2Q15	2Q14		2Q15	2Q14
Total MWh Generated (in thousands) [1]	*27,540*	*23,733*	*Average Capacity Factor, excl. Peakers*	*53.4%*	*41.7%*
West	8,430	6,770	West	54.7%	44.0%
Texas	11,618	9,912	Texas	55.8%	48.9%
East	7,492	7,051	East	48.7%	32.9%
Average Availability	*86.0%*	*88.1%*	*Steam Adjusted Heat Rate (Btu/KWh)*	*7,329*	*7,433*
West	82.8%	91.6%	West	7,325	7,377
Texas	87.7%	90.8%	Texas	7,078	7,282
East	87.0%	83.6%	East	7,738	7,694

	YTD15	YTD14		YTD15	YTD14
Total MWh Generated (in thousands) [1]	*53,836*	*47,485*	*Average Capacity Factor, excl. Peakers*	*52.7%*	*42.4%*
West	15,683	15,601	West	51.2%	51.1%
Texas	23,442	17,177	Texas	57.0%	44.2%
East	14,711	14,707	East	48.3%	34.1%
Average Availability	*87.7%*	*88.3%*	*Steam Adjusted Heat Rate (Btu/KWh)*	*7,296*	*7,393*
West	85.6%	90.3%	West	7,314	7,301
Texas	87.9%	86.9%	Texas	7,087	7,227
East	89.3%	88.0%	East	7,629	7,678

[1] Generation has been adjusted to include net interest in generation from our unconsolidated power plants and plants owned but not operated by us.

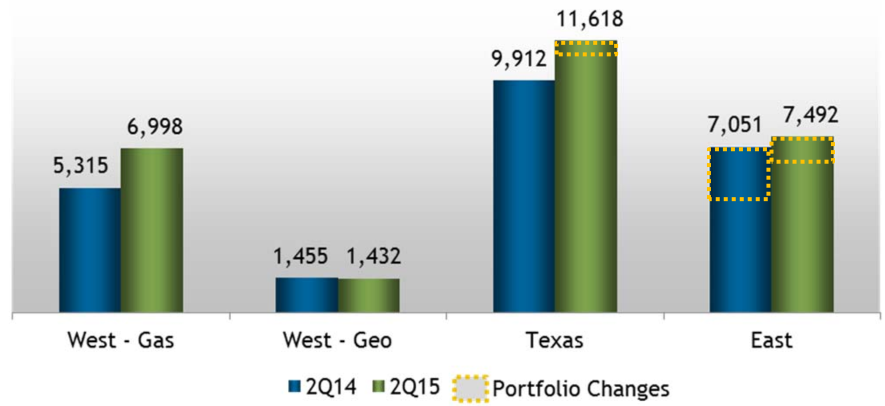
Focused on Best-in-Class Operations

Employee Total Reportable Incident Rate

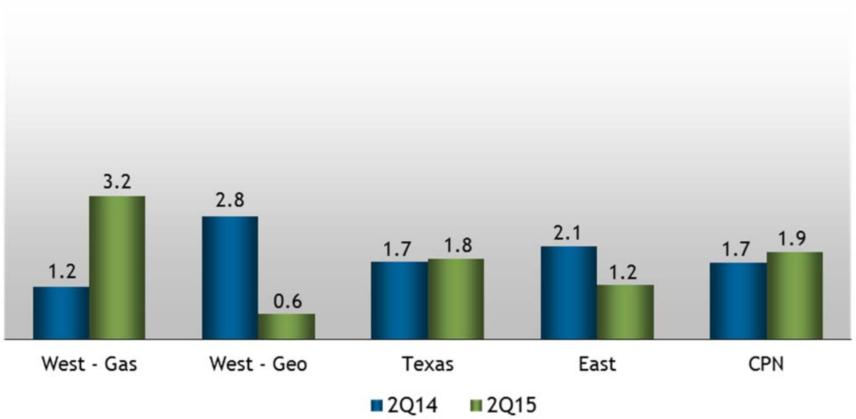


Generation in Key Markets (000 MWh)[1]

Key YoY Drivers:
↑ Low NW hydro + June heat
↑ More contracted dispatch
↑ Low nat gas prices
↑ Deer Park / Channel
↓ SE 6-Pack
↑ Fore River /Garrison
↑ Low nat gas prices



Forced Outage Factor (FOF, %)



Plants with no recordable injuries and < 2 % FOF for 2Q15

- ✓ Agnews
- ✓ Auburndale
- ✓ Bethlehem
- ✓ Bethpage 3
- ✓ Bosque
- ✓ Brazos Valley
- ✓ Clear Lake
- ✓ Corpus Christi
- ✓ Creed
- ✓ Deer Park
- ✓ Delta
- ✓ Feather River
- ✓ Fore River
- ✓ Freestone
- ✓ Geysers*
- ✓ Gilroy Peaker
- ✓ Goose Haven
- ✓ Guadalupe
- ✓ Hay Road
- ✓ Hermiston
- ✓ Kennedy
- ✓ King City
- ✓ King City Peaker
- ✓ Lambie
- ✓ Los Esteros
- ✓ Mankato
- ✓ Mid-Atlantic Peakers**
- ✓ Morgan
- ✓ Osprey
- ✓ Otay Mesa
- ✓ Pasadena
- ✓ Pastoria
- ✓ Pine Bluff
- ✓ Riverview
- ✓ Rockgen
- ✓ Russell City
- ✓ South Point
- ✓ Texas City
- ✓ Wolfskill
- ✓ York
- ✓ Yuba City
- ✓ Zion

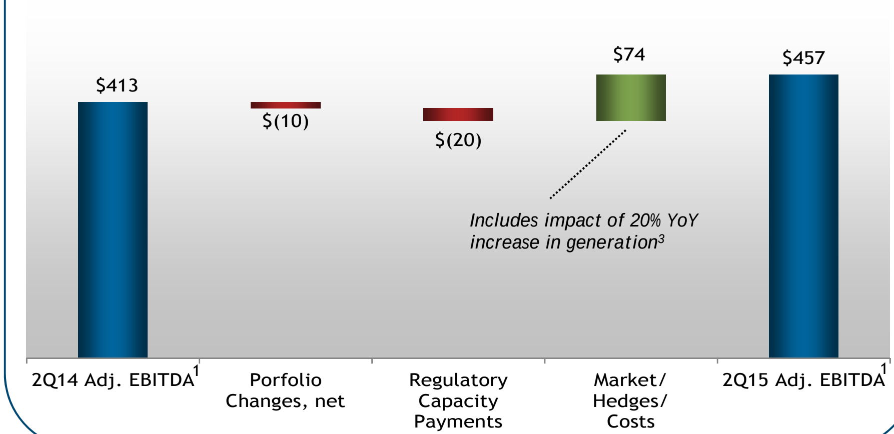
**Geysers includes: Aidlin, Big Geysers, Calistoga, Cobb Creek, Grant, Lake View, McCabe, Ridge Line, Socrates, Sonoma and Sulphur Springs.*
*** Mid-Atlantic Peakers includes: Bayview, Christiana, Crisfield, Delaware City, Mickleton, Sherman Ave., Tasley and West.*

[1] As compared to our SEC filings, generation shown here includes net interest in generation from our unconsolidated power plants and plants owned but not operated by us. [2] According to EEI Safety Survey (2014). Includes generation companies only.

Regional Adjusted EBITDA[1]: 2Q 2015 vs. 2014

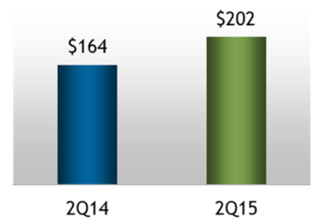
($ millions, 000 MWh)

Adjusted EBITDA[1] Drivers

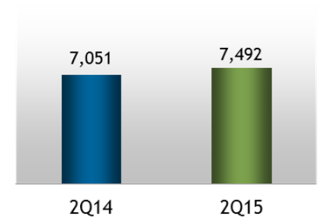


East Region

Adjusted EBITDA[1]



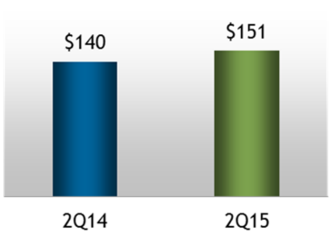
Generation[2]



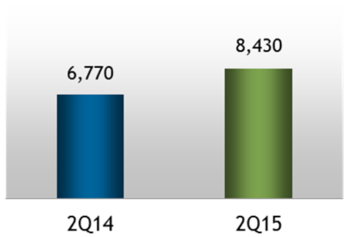
- Higher Commodity Margin[1]
  - + Acquisition of Fore River (4Q14), COD at Garrison (2Q15)
  - + Increased generation: higher spark spreads driven by lower natural gas prices
  - + Higher contribution from hedges
  - – SE Asset sale (3Q14)
  - – Lower regulatory capacity revenues in PJM

West Region

Adjusted EBITDA[1]



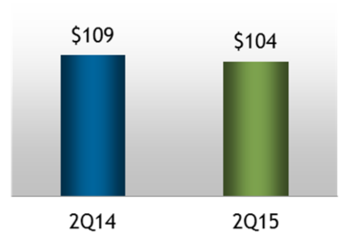
Generation[2]



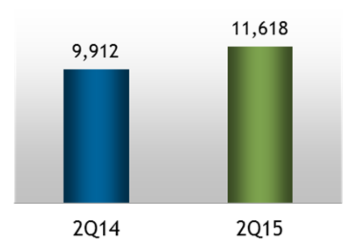
- Higher Commodity Margin[1]
  - + Higher contribution from hedges
  - + Stronger June 2015 market conditions, driven by warmer weather and decreased hydroelectric from the Northwest
  - + Higher renewable energy credit revenues

Texas Region

Adjusted EBITDA[1]



Generation[2]



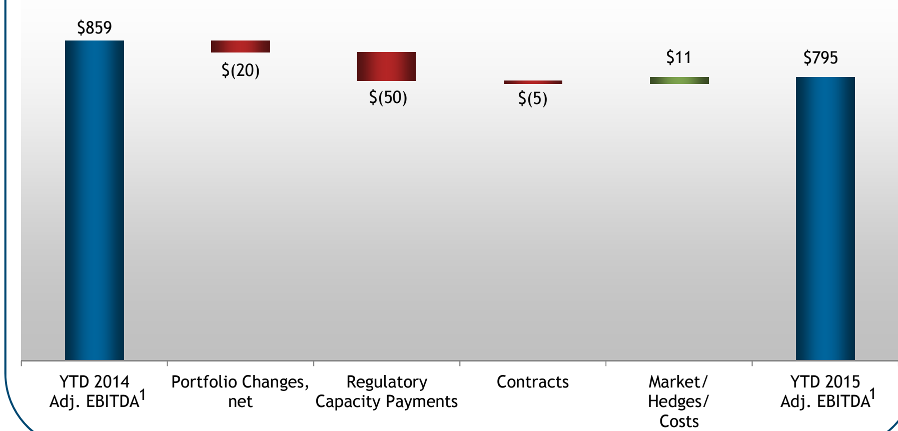
- Lower Commodity Margin[1]
  - – Lower on-peak spark spreads driven by lower natural gas prices
  - + Increased generation: lower natural gas prices
  - + Higher contribution from hedges
  - + Expansion of Deer Park and Channel Energy Centers (2Q14)

[1] A non-GAAP financial measure. Reconciliations of Commodity Margin to Income from Operations and of Adj. EBITDA to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.
[2] As compared to our SEC filings, generation shown here includes net interest in generation from unconsolidated projects and plants owned but not operated by us.
[3] Excludes net portfolio changes.

Regional Adjusted EBITDA[1]: YTD 2015 vs. 2014

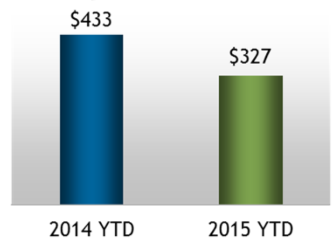
($ millions, 000 MWh)

Adjusted EBITDA[1] Drivers

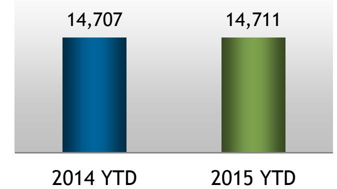


East Region

Adjusted EBITDA[1]



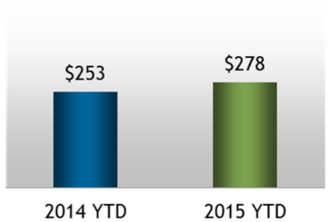
Generation[2]



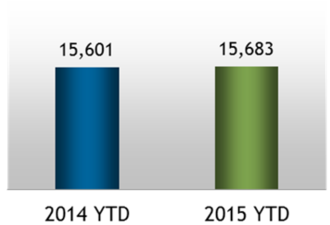
- Lower Commodity Margin[1]
  – Significantly lower power and natural gas prices in 1Q15 compared to unusually high levels in 1Q14 during polar vortex
  – SE asset sale (3Q14)
  – Lower regulatory capacity revenues in PJM
  + Acquisition of Fore River (4Q14), COD at Garrison (2Q15)
  + Higher contribution from hedges

West Region

Adjusted EBITDA[1]



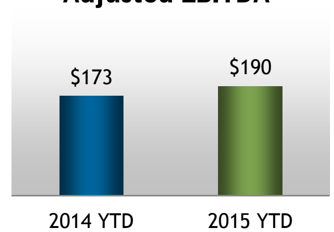
Generation[2]



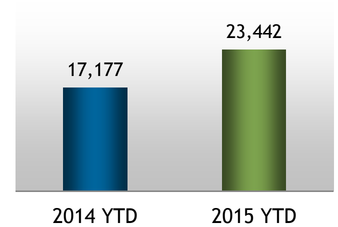
- Higher Commodity Margin[1]
  + Higher contribution from hedges
  + Higher renewable energy credit revenues
  – Lower on-peak spark spreads: lower natural gas prices

Texas Region

Adjusted EBITDA[1]



Generation[2]



- Higher Commodity Margin[1]
  + Acquisition of Guadalupe (1Q14), expansions of Deer Park and Channel (2Q14)
  + Higher contribution from hedges
  + Higher generation: lower natural gas prices
  – Lower on-peak spark spreads: lower natural gas prices

[1] A non-GAAP financial measure. Reconciliations of Commodity Margin to Income from Operations and of Adj. EBITDA to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.
[2] As compared to our SEC filings, generation shown here includes net interest in generation from unconsolidated projects and plants owned but not operated by us.

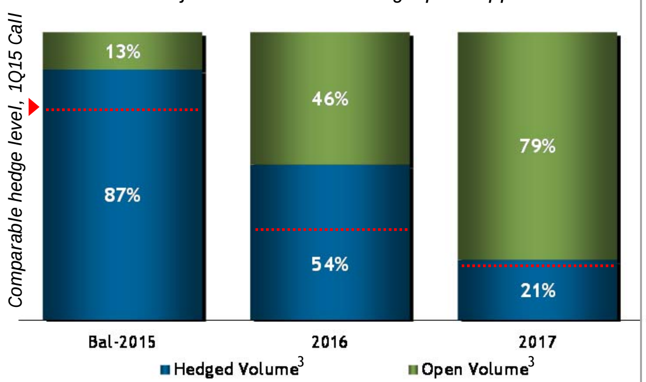
Energy Margin[1]:
Positioned to Respond to Favorable Secular Trends

Energy Hedge Profile[2]

$ Energy Margin[1,2] as % of
Total Commodity Margin (by year):

76%	*73%*	*72%*

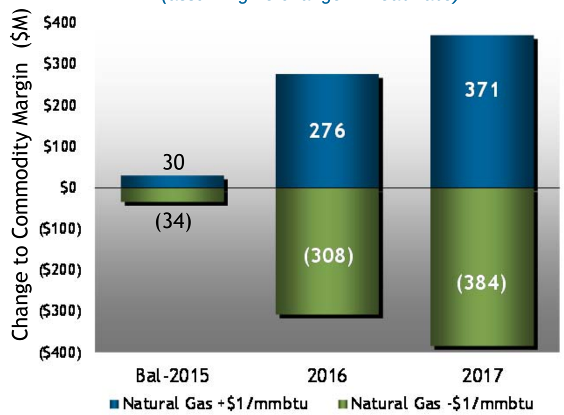
Use in conjunction with modeling tips in appendix



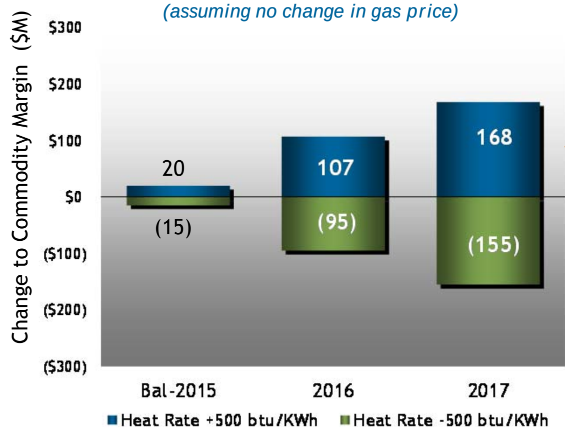
	2015	2016	2017
Hedged Margin ($/MWh)[2]	$18	$19	$28
Avg. MW in Operation[2,4] *(excl. unconsol.)*	26,064	26,136	25,997

Sensitivities

Natural Gas Price Sensitivity[2]
(assuming no change in heat rate)



Market Heat Rate Sensitivity[2]
(assuming no change in gas price)



Capturing the Champion Acquisition:

- Disclosures do not yet incorporate acquisition; expected by 3Q15 call
- Meanwhile, utilize 4-5x initial Adj. EBITDA to approximate acquisition impact

Reminder:

- Market heat rates tend to show inverse relationships with gas prices in some markets
- ±500 btu/kWh sensitivity shown here, but inverse relationship historically much stronger at lower gas prices

2015 OnPk Spark Spread[5]		Last Call (4/17/15)	This Call (7/17/15)
	NP-15	$9.74	$10.78
	ERCOT	$14.40	$12.26
	PJM-W	$23.66	$22.61
	NEPOOL	$19.14	$16.60
	Nat Gas (HH)	$2.80	$2.87

2016 OnPk Spark Spread[5]		Last Call (4/17/15)	This Call (7/17/15)
	NP-15	$8.23	$9.34
	ERCOT	$16.03	$14.38
	PJM-W	$22.48	$22.01
	NEPOOL	$21.41	$19.36
	Nat Gas (HH)	$3.11	$3.18

See footnotes on slide 29 in appendix.

Energy Margin[1]: Positioned to Respond to Favorable Secular Trends

Slide 28 Footnote References

[1] Energy Margin + Regulatory & Other Margin = Total Commodity Margin.

[2] Estimated as of 07/17/15. Excludes immaterial proprietary positions as well as impact of pending Champion retail acquisition. Hedged margin excludes unconsolidated projects and includes the current mark-to-market adjustments of all executed transactions. Changing market heat rates will change delta volumes and gas price exposures. Sensitivities are assumed to occur across the portfolio and the sensitivities on strategic options only capture intrinsic value.

[3] Volumes are on a delta hedge basis. Delta volumes are the expected volume based on the probability of economic dispatch at a future date based on current market prices for that future date. This is lower than the notional volume, which is plant capacity, less known performance and operating constraints. In addition to planned upgrades, volumes assume addition of York 2 and sale of Osprey (2017). Sale of Osprey is subject to regulatory approvals.

[4] Represents Calpine's forecasted average annual capacity of net ownership interest with peaking capacity, excluding equity plants. Capacity additions/deletions are reflected in anticipated month of completion.

[5] Spark spread in NP-15, ERCOT and NEPOOL based upon 7,000 btu/kWh production heat rate and in PJM-W based upon 8,000 btu/kWh production heat rate. NP-15 adjusted to deduct cost of carbon cap-and-trade, without which, spark spreads as of 4/17/15 and 7/17/15 would have been $14.48 and $15.55, respectively, for Cal-2015 and $13.10 and $14.22, respectively, for Cal-2016.

Although Calpine's fleet can be difficult to model, simplifying techniques may help

1. Estimate annual generation (MWh) based on market outlook relative to disclosed historical generation with adjustments for asset acquisitions, asset divestitures and plants reaching commercial operations as well as changes in gas and coal price environments.
   - Note: Estimated generation in this step should *exclude* volumes from unconsolidated investments (Greenfield, Whitby). Margin from these plants is captured in step 7 below.
2. Estimate hedged energy margin based on disclosed % hedged (blue bars) and disclosed hedge margin ($/MWh).
   - Note: 2015 hedged margin ($/MWh) is full year average including YTD settlements. 2015 hedge profile is for balance of year only (applicable for steps 3 and 4 as well).
3. Estimate Geysers unhedged energy margin using MWh estimate (historically, ~6 million MWhs), assume the Geysers unhedged % is the same as the entire portfolio, and apply NP-15 ATC prices.
4. Estimate gas fleet unhedged energy margin based on rough assumptions:
   - Dispatched generation tends to capture a premium to the block on-peak spark spread for open volume. This premium varies significantly with, and is inversely related to, dispatch volumes. For 2015, this relationship is captured within our guidance. *For years past 2015*, depending upon your volume assumption in step 1 above, use the following rules of thumb for applying the premium:

Volume Projection *(excl. unconsolidated)* **(MM MWh)**	**Recommended Premium to On-Peak Spark Spread**
<100	10% - 20%
100 – 110	0% - 10%
110 – 120…	(10)% - 0%

   - For this exercise, hedge profile is assumed to be relatively flat across all regions, and disclosed regional steam adjusted plant heat rates should be considered when calculating spark spreads.
5. Adjust margin to capture items such as ancillary services and storage positions (benefit of small tens of millions), as well as carbon costs in California.
   - To consider Calpine's AB32 costs, apply our combined-cycle average emissions rate of 852 lb/MWh for the California combined-cycle plants and assume that ~50% of those costs are passed on to our customers per contractual arrangements. Note: This step is only required if the on-peak spark spread used in step 4 has not been adjusted to capture carbon cost in California.
6. The sum of steps 2 through 5 above will provide you with an estimate of our Energy Margin. To estimate the contribution of Reliability and Other Margin (regulatory capacity and REC revenue) and arrive at an estimate of Total Commodity Margin, simply divide the Energy Margin by the disclosed percentages of Energy Margin as a % of total Commodity Margin.
7. Add estimated margin from unconsolidated investments (Greenfield, Whitby) by multiplying Calpine capacity (net interest) by $110/kw-yr in all periods shown.
   - Since these margins from unconsolidated investments are not included in Commodity Margin, but are included in Adjusted EBITDA, it is necessary to additionally estimate expenses related to unconsolidated investments for purposes of calculating Adjusted EBITDA.
8. When modeling operating costs for the consolidated power plants, use 2014 reported plant operating expense[1] and sales, general and administrative expense[2] and other operating expense and apply an inflationary factor for 2015 and subsequent periods, with adjustments for asset acquisitions, asset divestitures and plants reaching commercial operations.
9. To capture the impact of the pending Champion Energy acquisition, apply rule of thumb that purchase price approximates 4 – 5x initial Adjusted EBITDA, using acquisition price of $240 million[3].

Note: Tips are provided to help investors consider simplifying techniques to apply the information disclosed to date in their modeling efforts. These tips are naturally less precise than models based on detailed operational, contract, and hedge position data might be.

[1] Excluding major maintenance expense, non-cash loss on disposal of assets, and stock-based compensation.
[2] Excluding stock-based compensation.
[3] Subject to working capital adjustments.

Capital Structure Chart

($ in millions)

Corporate Debt	
Senior Secured Notes	$1,928
First Lien Term Loans	$2,787
Unsecured Notes[1]	$3,450
Corporate Revolver	—
Total Corporate Debt	$8,165

Project Debt	CCFC	Capital Lease Obligations & Other
$1,729	$1,588	$209

Project Debt – Projects
- Steamboat
  - *Freeport*
  - *Mankato*
- Bethpage
- Otay Mesa
- Pasadena
- Russell City
- Los Esteros

CCFC – Projects
- Brazos Valley
- Magic Valley
- Bosque
- Hermiston
- Osprey
- Westbrook
- Guadalupe

Capital Lease Obligations & Other – Projects
- Hidalgo
- King City
- Stony Brook
- Other

Total Debt:	$ 11,691
Less: 25% Russell City Debt[1]	(142)
Add: Net Debt from Unconsolidated Projects[2]	127
Less: Cash, Cash Equivalents & Restr. Cash	(632)
Net Debt	$ 11,044

Net Debt / Adjusted EBITDA[3] = 5.4x

All balances as of 6/30/15.
[1] Equal to minority interest in debt associated with Russell City Energy Center.
[2] Equal to our net interest in total debt, less cash and cash equivalents and restricted cash from unconsolidated projects.
[3] Calculation based upon midpoint of 2015 Adjusted EBITDA guidance, excluding effective corporate debt (equivalent capital spend) for Garrison and York 2 projects (partial year / under construction).

Why You Should Invest in Calpine Today

Slide 21 Footnote References

CALPINE

[1] Based upon closing stock price on 7/29/15. 2015 yield based upon midpoint of guidance range. [2] A non-GAAP financial measure. Reconciliations of Adj. EBITDA and Adj. FCF to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix. [3] See related assumptions below. [4] Based upon 360 M shares outstanding as of 7/28/15. Consistent with analyst estimates, assumes $175/MW-day clearing price for 2018/19 PJM CP product. (For every ±$25/MW-day variance from consensus, results will vary by ±$0.08.) Includes results of 2018/19 New England auction. Shown net of changes in contracts. Excludes future capital allocation.

Below are relevant footnotes and assumptions to support the implied $/kW referenced on slide 21 in this presentation. The calculations shown below are illustrative and are based upon certain assumptions, including those from third parties.

	Value ($MM, except per share)	Capacity (MW)	Value ($/kW)	
Enterprise Value:				
Calpine share price (07/29/15)	$16.63			
Shares outstanding (MM)(1)	360			
Market value of equity	$ 5,988			
Net debt(2)	10,937			
PV of operating leases(3)	200			
Noncontrolling interest(4)	57			
Total Enterprise Value (5)	*$ 17,182*	*26,742*	*$ 643*	
Less: Non-CCGT/Cogen Value Drivers				
PV of NOLs(3)	1,100			
Projects under construction(6)	312			
Retail acquisition, at cost(7)	240			
Geysers(8)	2,900	729		
Peakers(9)	900	2,985		
Russell City / LECEF(10)	1,650	928		
Implied CCGT/Cogen Value	*$ 10,080*	*22,100*	*$ 455*	
Assumed Cogen Premium			50%	0%
Implied CCGT Value (11)			***$ 391***	***$ 455***

~$400 - $450 / kW

Notes:

(1) Shares outstanding as of 7/28/15.
(2) Equal to total debt as of 6/30/15, less cash and cash equivalents and restricted cash, plus net debt from unconsolidated projects. Includes 100% of project debt associated with Russell City Energy Center, of which we own a 75% share. Adjusted to include remaining 2015 Adj. FCF[2] (based upon midpoint of guidance range), less remaining growth capex and cash to fund Champion acquisition.
(3) Based upon average of sell-side analyst estimates, where available.
(4) Represents our equity partner's 25% interest in RCEC.
(5) Capacity corresponding to Total Enterprise Value reflects RCEC at 100%, as we include 100% of the project debt for purposes of consolidation. See note (2) above.
(6) Equal to Construction in Progress balance as of 6/30/15.
(7) Subject to working capital adjustments.
(8) Assumes $4,000/kW valuation, which we believe to be conservative. Capacity includes Vineland solar project (4 MW).
(9) Represents all simple-cycle generating capacity. Assumes $300/kW valuation, which we believe to be conservative.
(10) Assumes ~9.0x Adj. EBITDA, which we believe to be conservative.
(11) Assuming a premium range of 0 - 50% for cogens (as compared to CCGTs), implied value of CCGTs is ~$400 - $450/kW.

Calpine[1] Continues to Benefit from Federal NOL Positions

- Federal NOLs at Dec. 31, 2014: $6.9 billion
  - All are unrestricted

[1] Includes CCFC.

Calpine Operating Power Plants

As of July 30, 2015

	Technology	Load Type	Location	COD	With Peaking Capacity	CPN Interest	With Peaking Capacity, Net
West Region							
Agnews Power Plant	Natural Gas	Intermediate	CA	1990	28	100%	28
Creed Energy Center	Natural Gas	Peaking	CA	2003	47	100%	47
Delta Energy Center	Natural Gas	Intermediate	CA	2002	857	100%	857
Feather River Energy Center	Natural Gas	Peaking	CA	2002	47	100%	47
Geysers (14 plants)	Geothermal	Baseload	CA	1971 - 1989	725	100%	725
Gilroy Cogeneration Plant*	Natural Gas	Intermediate	CA	1988	130	100%	130
Gilroy Energy Center	Natural Gas	Peaking	CA	2002	141	100%	141
Goose Haven Energy Center	Natural Gas	Peaking	CA	2003	47	100%	47
Hermiston Power Project	Natural Gas	Intermediate	OR	2002	635	100%	635
King City Cogeneration Plant*	Natural Gas	Intermediate	CA	1989	120	100%	120
King City Peaking Energy Center	Natural Gas	Peaking	CA	2002	44	100%	44
Lambie Energy Center	Natural Gas	Peaking	CA	2003	47	100%	47
Los Esteros Critical Energy Facility	Natural Gas	Intermediate	CA	2013	309	100%	309
Los Medanos Energy Center*	Natural Gas	Intermediate	CA	2001	572	100%	572
Metcalf Energy Center	Natural Gas	Intermediate	CA	2005	605	100%	605
Otay Mesa Energy Center	Natural Gas	Intermediate	CA	2009	608	100%	608
Pastoria Energy Center	Natural Gas	Intermediate	CA	2005	749	100%	749
Riverview Energy Center	Natural Gas	Peaking	CA	2003	47	100%	47
Russell City Energy Center	Natural Gas	Intermediate	CA	2013	619	75%	464
South Point Energy Center	Natural Gas	Intermediate	AZ	2001	530	100%	530
Sutter Energy Center	Natural Gas	Intermediate	CA	2001	578	100%	578
Wolfskill Energy Center	Natural Gas	Peaking	CA	2003	48	100%	48
Yuba City Energy Center	Natural Gas	Peaking	CA	2002	47	100%	47
Total - West Region							**7,425**
Texas Region							
Baytown Energy Center*	Natural Gas	Intermediate	TX	2002	842	100%	842
Bosque Energy Center	Natural Gas	Intermediate	TX	2000/2011	762	100%	762
Brazos Valley Power Plant	Natural Gas	Intermediate	TX	2003	609	100%	609
Channel Energy Center*	Natural Gas	Intermediate	TX	2001	808	100%	808
Clear Lake Power Plant*	Natural Gas	Intermediate	TX	1985	400	100%	400
Corpus Christi Energy Center*	Natural Gas	Intermediate	TX	2002	500	100%	500
Deer Park Energy Center*	Natural Gas	Intermediate	TX	2003	1,204	100%	1,204
Freeport Energy Center*	Natural Gas	Intermediate	TX	2007	236	100%	236
Freestone Energy Center	Natural Gas	Intermediate	TX	2002	994	75%	746
Guadalupe Energy Center	Natural Gas	Intermediate	TX	2001/2011	1,000	100%	1,000
Hidalgo Energy Center	Natural Gas	Intermediate	TX	2000	476	79%	374
Magic Valley Generation Station	Natural Gas	Intermediate	TX	2002	712	100%	712
Pasadena Power Plant*	Natural Gas	Intermediate	TX	1998	781	100%	781
Texas City Power Plant*	Natural Gas	Intermediate	TX	1987	453	100%	453
Total - Texas Region							**9,427**

Calpine Operating Power Plants (cont'd)

As of July 30, 2015

	Technology	Load Type	Location	COD	With Peaking Capacity	CPN Interest	With Peaking Capacity, Net
East Region							
Auburndale Peaking Energy Center	Natural Gas	Peaking	FL	2002	117	100%	117
Bayview	Oil	Peaking	VA	1963	12	100%	12
Bethlehem	Natural Gas / Oil	Intermediate	PA	2003	1,130	100%	1,130
Bethpage Energy Center 3	Natural Gas	Intermediate	NY	2005	80	100%	80
Bethpage Peaker	Natural Gas	Peaking	NY	2002	48	100%	48
Bethpage Power Plant	Natural Gas	Intermediate	NY	1989	56	100%	56
Cumberland	Natural Gas / Oil	Peaking	NJ	1990/2009	191	100%	191
Edge Moor*	Natural Gas / Oil	Peaking	DE	1965	725	100%	725
Fore River Energy Center	Natural Gas / Oil	Intermediate	MA	2003	731	100%	731
Garrison Energy Center	Natural Gas	Intermediate	DE	2015	309	100%	309
Greenfield Energy Centre	Natural Gas	Intermediate	Ontario, CA	2008	1,038	50%	519
Hay Road	Natural Gas / Oil	Intermediate	DE	1989	1,130	100%	1,130
Kennedy Int'l Airport Power Plant*	Natural Gas	Intermediate	NY	1995	121	100%	121
Mankato Power Plant	Natural Gas	Intermediate	MN	2006	375	100%	375
Mid-Atlantic Peakers**	Natural Gas / Oil	Peaking	NJ/DE/MD/VA	1965-1991	371	100%	371
Morgan Energy Center*	Natural Gas	Intermediate	AL	2003	807	100%	807
Osprey Energy Center	Natural Gas	Intermediate	FL	2004	599	100%	599
Pine Bluff Energy Center*	Natural Gas	Intermediate	AR	2001	215	100%	215
RockGen Energy Center	Natural Gas	Peaking	WI	2001	503	100%	503
Stony Brook Power Plant*	Natural Gas	Intermediate	NY	1995	47	100%	47
Vineland Solar	Solar	Peaking	NJ	2009	4	100%	4
Westbrook Energy Center	Natural Gas	Intermediate	ME	2001	552	100%	552
Whitby Cogen*	Natural Gas	Intermediate	Ontario, CA	1998	50	50%	25
York Energy Center	Natural Gas	Intermediate	PA	2011	565	100%	565
Zion Energy Center	Natural Gas	Peaking	IL	2002	503	100%	503
Total - East Region							**9,735**
TOTAL - CALPINE							**26,587**
Projects Under Construction							
York 2 Energy Center	Natural Gas	Intermediate	PA	2017 (est)	760	100%	760
Projects Under Advanced Development							
Guadalupe Peaking Energy Center	Natural Gas	Peaking	TX	2017-19 (est)	418	100%	418
Mankato Energy Center Expansion	Natural Gas	Intermediate	MN	2018-19 (est)	345	100%	345

* Indicates cogeneration plant

** Includes Carll's Corner, Christiana, Crisfield, Delaware City, Mickleton, Sherman Avenue, Tasley, West.

Reg G Reconciliation: Commodity Margin

($ in millions)

Commodity Margin includes our power and steam revenues, sales of purchased power and physical natural gas, capacity revenue, revenue from renewable energy credits, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, environmental compliance expense and realized settlements from our marketing, hedging, optimization and trading activities, but excludes mark-to-market activity and other revenues. We believe that Commodity Margin is a useful tool for assessing the performance of our core operations and is a key operational measure reviewed by our chief operating decision maker. Commodity Margin does not intend to represent income from operations, the most comparable U.S. GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly-titled measures reported by other companies.

	Three Months Ended June 30, 2015				
	West	Texas	East	Consolidation And Elimination	Total
Commodity Margin	$ 240	$ 170	$ 247	$ —	$ 657
Add: Mark-to-market commodity activity, net and other[1]	(14)	10	30	(7)	19
Less:					
Plant operating expense	120	82	77	(7)	272
Depreciation and amortization expense	65	50	45	—	160
Sales, general and other administrative expense	6	15	9	—	30
Other operating expenses	10	2	8	—	20
(Income) from unconsolidated investments in power plants	—	—	(7)	—	(7)
Income from operations	$ 25	$ 31	$ 145	$ —	$ 201

	Three Months Ended June 30, 2014				
	West	Texas	East	Consolidation And Elimination	Total
Commodity Margin[2]	$ 228	$ 177	$ 227	$ —	$ 632
Add: Mark-to-market commodity activity, net and other[1]	21	184	(24)	(8)	173
Less:					
Plant operating expense	95	83	103	(7)	274
Depreciation and amortization expense	58	48	40	1	147
Sales, general and other administrative expense	7	18	12	1	38
Other operating expenses	15	1	9	(4)	21
(Income) from unconsolidated investments in power plants	—	—	(4)	—	(4)
Income from operations	$ 74	$ 211	$ 43	$ 1	$ 329

Reg G Reconciliation:
Commodity Margin (continued)

($ in millions)

Commodity Margin includes our power and steam revenues, sales of purchased power and physical natural gas, capacity revenue, revenue from renewable energy credits, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, environmental compliance expense and realized settlements from our marketing, hedging, optimization and trading activities, but excludes mark-to-market activity and other revenues. We believe that Commodity Margin is a useful tool for assessing the performance of our core operations and is a key operational measure reviewed by our chief operating decision maker. Commodity Margin does not intend to represent income from operations, the most comparable U.S. GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly-titled measures reported by other companies.

	Six Months Ended June 30, 2015				
	West	Texas	East	Consolidation And Elimination	Total
Commodity Margin	$ 458	$ 319	$ 415	$ —	$ 1,192
Add: Mark-to-market commodity activity, net and other[(3)]	105	51	(22)	(14)	120
Less:					
Plant operating expense	226	171	149	(14)	532
Depreciation and amortization expense	132	99	87	—	318
Sales, general and other administrative expense	16	32	19	—	67
Other operating expenses	20	4	16	—	40
(Income) from unconsolidated investments in power plants	—	—	(12)	—	(12)
Income from operations	$ 169	$ 64	$ 134	$ —	$ 367

	Six Months Ended June 30, 2014				
	West	Texas	East	Consolidation And Elimination	Total
Commodity Margin[(2)]	$ 430	$ 298	$ 549	$ —	$ 1,277
Add: Mark-to-market commodity activity, net and other[(3)]	50	138	(35)	(17)	136
Less:					
Plant operating expense	200	173	182	(16)	539
Depreciation and amortization expense	118	90	91	1	300
Sales, general and other administrative expense	17	30	24	—	71
Other operating expenses	27	3	16	(3)	43
(Income) from unconsolidated investments in power plants	—	—	(13)	—	(13)
Income from operations	$ 118	$ 140	$ 214	$ 1	$ 473

(1) Includes $(18) million and $(27) million of lease levelization and $3 million and $3 million of amortization expense for the three months ended June 30, 2015 and 2014, respectively.

(2) Commodity Margin related to the six power plants sold in our East segment on July 3, 2014, was $42 million and $81 million for the three and six months ended June 30, 2014, respectively.

(3) Includes $(42) million and $(56) million of lease levelization and $7 million and $7 million of amortization expense for the six months ended June 30, 2015 and 2014, respectively.

Reg G Reconciliation:
Adjusted EBITDA and Adjusted Free Cash Flow

CALPINE

($ in millions, except share and per share amounts)

Adjusted EBITDA represents net income (loss) attributable to Calpine before net income (loss) attributable to the noncontrolling interest, interest, taxes, depreciation and amortization, adjusted for certain non-cash and non-recurring items as detailed in the following reconciliation. Adjusted EBITDA is not intended to represent cash flows from operations or net income (loss) as defined by U.S. GAAP as an indicator of operating performance and is not necessarily comparable to similarly-titled measures reported by other companies. We believe Adjusted EBITDA is useful to investors and other users of our financial statements in evaluating our operating performance because it provides them with an additional tool to compare business performance across companies and across periods. We believe that EBITDA is widely used by investors to measure a company's operating performance without regard to such items as interest expense, taxes, depreciation and amortization, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired. Additionally, we believe that investors commonly adjust EBITDA information to eliminate the effects of restructuring and other expenses, which vary widely from company to company and impair comparability. We adjust for these and other items as our management believes that these items would distort their ability to efficiently view and assess our core operating trends.

In summary, our management uses Adjusted EBITDA as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends, as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations, and in communications with our Board of Directors, shareholders, creditors, analysts and investors concerning our financial performance.

Adjusted Free Cash Flow represents net income before interest, taxes, depreciation and amortization, as adjusted, less operating lease payments, major maintenance expense and maintenance capital expenditures, net cash interest, cash taxes, and other adjustments, including non-recurring items. Adjusted Free Cash Flow is a performance measure and is not intended to represent net income (loss), the most directly comparable U.S. GAAP measure, or liquidity and is not necessarily comparable to similarly titled measures reported by other companies.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014[6]	2015	2014[6]
Net income attributable to Calpine	$ 19	$ 139	$ 9	$ 122
Net income attributable to the noncontrolling interest	2	2	5	6
Income tax expense (benefit)	5	15	4	(4)
Debt modification and extinguishment costs and other (income) expense, net	18	6	39	17
Interest expense, net of interest income	157	167	310	332
Income from operations	$ 201	$ 329	$ 367	$ 473
Add:				
Adjustments to reconcile income from operations to Adjusted EBITDA:				
Depreciation and amortization expense, excluding deferred financing costs[1]	159	146	316	297
Major maintenance expense	90	72	168	153
Operating lease expense	8	8	17	17
Mark-to-market (gain) loss on commodity derivative activity	1	(141)	(69)	(68)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude the noncontrolling interest[2]	4	6	9	9
Stock-based compensation expense	1	12	12	22
Loss on dispositions of assets	2	1	3	1
Acquired contract amortization	3	3	7	7
Other	(12)	(23)	(35)	(52)
Total Adjusted EBITDA	$ 457	$ 413	$ 795	$ 859
Less:				
Operating lease payments	8	8	17	17
Major maintenance expense and capital expenditures[3]	136	126	279	259
Cash interest, net[4]	157	169	312	337
Cash taxes	11	8	17	14
Other	1	3	1	3
Adjusted Free Cash Flow[5]	$ 144	$ 99	$ 169	$ 229
Weighted average shares of common stock outstanding (diluted, in thousands)	369,946	421,348	373,404	422,697
Adjusted Free Cash Flow Per Share (diluted)	$ 0.39	$ 0.23	$ 0.45	$ 0.54

(1) Depreciation and amortization expense in the income from operations calculation on our Consolidated Condensed Statements of Operations excludes amortization of other assets.

(2) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include (gain) loss on mark-to-market activity of nil for the three and six months ended June 30, 2015 and 2014.

(3) Includes $90 million and $169 million in major maintenance expense for the three and six months ended June 30, 2015, respectively, and $46 million and $110 million in maintenance capital expenditure for the three and six months ended June 30, 2015, respectively. Includes $73 million and $156 million in major maintenance expense for the three and six months ended June 30, 2014, respectively, and $53 million and $103 million in maintenance capital expenditure for the three and six months ended June 30, 2014, respectively.

(4) Includes commitment, letter of credit and other bank fees from both consolidated and unconsolidated investments, net of capitalized interest and interest income.

(5) Excludes an increase in working capital of $165 million and $251 million for the three and six months ended June 30, 2015, respectively, and an increase in working capital of $36 million and $42 million for the three and six months ended June 30, 2014, respectively. Adjusted Free Cash Flow, as reported, excludes changes in working capital, such that it is calculated on the same basis as our guidance.

(6) Adjusted EBITDA related to the six power plants sold in our East segment on July 3, 2014, was $23 million and $43 million for the three and six months ended June 30, 2014, respectively.

Reg G Reconciliation: 2015 Adjusted EBITDA and Adjusted Free Cash Flow Guidance

CALPINE

Full Year 2015 Range:	Low	High
GAAP Net Income [1]	$ 298	$ 398
Plus:		
Debt modification and extinguishment costs	32	32
Interest expense, net of interest income	630	630
Depreciation and amortization expense	630	630
Major maintenance expense	245	245
Operating lease expense	35	35
Other[2]	80	80
Adjusted EBITDA	$ 1,950	$ 2,050
Less:		
Operating lease payments	35	35
Major maintenance expense and maintenance capital expenditures[3]	415	415
Cash interest, net[4]	630	630
Cash taxes	25	25
Other	5	5
Adjusted Free Cash Flow	$ 840	$ 940

(1) For purposes of Net Income guidance reconciliation, mark-to-market adjustments are assumed to be nil.

(2) Other includes stock-based compensation expense, adjustments to reflect Adjusted EBITDA from unconsolidated investments, income tax expense and other items.

(3) Includes projected major maintenance expense of $250 million and maintenance capital expenditures of $165 million. Capital expenditures exclude major construction and development projects.

(4) Includes commitment, letter of credit and other bank fees from both consolidated and unconsolidated investments, net of capitalized interest and interest income.

Major Maintenance and Capital Expenditure Guidance

($ in millions)

		2015E	
Major maintenance expense	$	250	*A*
Maintenance capital expenditures		165	*B*
Growth-related capital expenditures[1]		355	*C*
Capital expenditures, gross[2]	$	520	
Less: Capital expenditures funded with financing		–	*D*
Capital expenditures, net of financing	$	520	
Acquisition of Champion Energy[3]	$	240	

Reconciling to our Guidance Summary:

Major maintenance expense and maintenance capital expenditures	$ 415	*A + B*
Growth-related capital expenditures, net of debt funding[2]	355	*C – D*

[1] Primarily includes expenditures associated with Garrison and York 2 Energy Centers.
[2] Excludes acquisitions.
[3] Subject to working capital adjustments.

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