NRG's Third Quarter 2010 Results Presentation

November 4, 2010

Safe Harbor Statement

This Investor Presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are subject to certain risks, uncertainties and assumptions and typically can be identified by the use of words such as “expect,” “estimate,” “should,” “anticipate,” “forecast,” “plan,” “guidance,” “believe” and similar terms. Such forward-looking statements include our adjusted EBITDA and free cash flow guidance, expected earnings, future growth and financial performance, commercial operations and renewable energy development strategy, and nuclear development. Although NRG believes that its expectations are reasonable, it can give no assurance that these expectations will prove to have been correct, and actual results may vary materially. Factors that could cause actual results to differ materially from those contemplated above include, among others, general economic conditions, hazards customary in the power industry, weather conditions, competition in wholesale power markets, the volatility of energy and fuel prices, failure of customers to perform under contracts, changes in the wholesale power markets, changes in government regulation of markets and of environmental emissions, the condition of capital markets generally, our ability to access capital markets, unanticipated outages at our generation facilities, adverse results in current and future litigation, failure to identify or successfully implement acquisitions and repowerings, the inability to implement value enhancing improvements to plant operations and companywide processes, the inability to obtain federal loan guarantees, the inability to maintain or create successful partnering relationships, the inability to retain retail customers, and our ability to realize value through our commercial operations strategy.

NRG undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law. The adjusted EBITDA, and free cash flow guidance are estimates as of November 4, 2010 and are based on assumptions believed to be reasonable as of that date. NRG disclaims any current intention to update such guidance from November 4, 2010, except as required by law. The foregoing review of factors that could cause NRG’s actual results to differ materially from those contemplated in the forward-looking statements included in this Investor Presentation should be considered in connection with information regarding risks and uncertainties that may affect NRG's future results included in NRG's filings with the Securities and Exchange Commission at www.sec.gov. Statements made in connection with the exchange offer are not subject to the safe harbor protections provided to forward-looking statements under Private Securities Litigation Reform Act.

Agenda

- Business Highlights & Strategic Review – *D. Crane*
- Operational and Commercial Review – *M. Gutierrez*
- Financial Results – *C. Schade*
- Closing Remarks and Q&A – *D. Crane*

Third Quarter 2010: Key Highlights

- **$777 million Adjusted EBITDA** and $536 million Cash from Operations driven by solid execution in both retail and wholesale

- **$4.8 billion Total Liquidity**, with $3.5 billion of cash on hand and proforma cash of $1.2 billion, post asset acquisitions

- **2010 Adjusted EBITDA guidance revised to upper end of range to $2,500 to $2,550 million** and Free Cash Flow Guidance in range of $699 to $749 million post growth investments

- **Initial 2011 Guidance**
  - Adjusted EBITDA: $1,900 to $2,100 million
  - Free Cash Flow*: $950 to $1,150 million

  (*after maintenance and environmental CapEx, but before growth CapEx)

Robust Results Defy Commodity Price Curve

NRG: A Mutually Reinforcing Dual Strategy

G R E E N E R

Continue to Build and Operate Best-in-Class Conventional Fleet	Transforming to a post-hydrocarbon provider of green energy solutions
Priorities:	**Priorities:**
☑ Focus on operational excellence in wholesale and in retail	☑ Low Carbon Baseload, principally new advanced nuclear and CCS/EOR
☑ Optimize wholesale & retail hedging and margins through all commodity cycles	☑ **Renewable Generation…with a concentration in solar**
☑ Pursue repowering of conventional projects on existing sites, with investment returns in excess of WACC	☑ **Green Retail in Competitive Markets**
☑ Drive appropriate capital allocation	☑ Electric Vehicle Ecosystems
☑ **Explore cash accretive acquisition opportunities in our core markets at discounts to replacement cost**	☑ Smart grid and other sustainable energy services

G R E E N E S T

Consumer Driven

★ Our Goal: To deliver exemplary results while transforming the business model to capture high growth/high return opportunities ★

NRG Classic Fleet

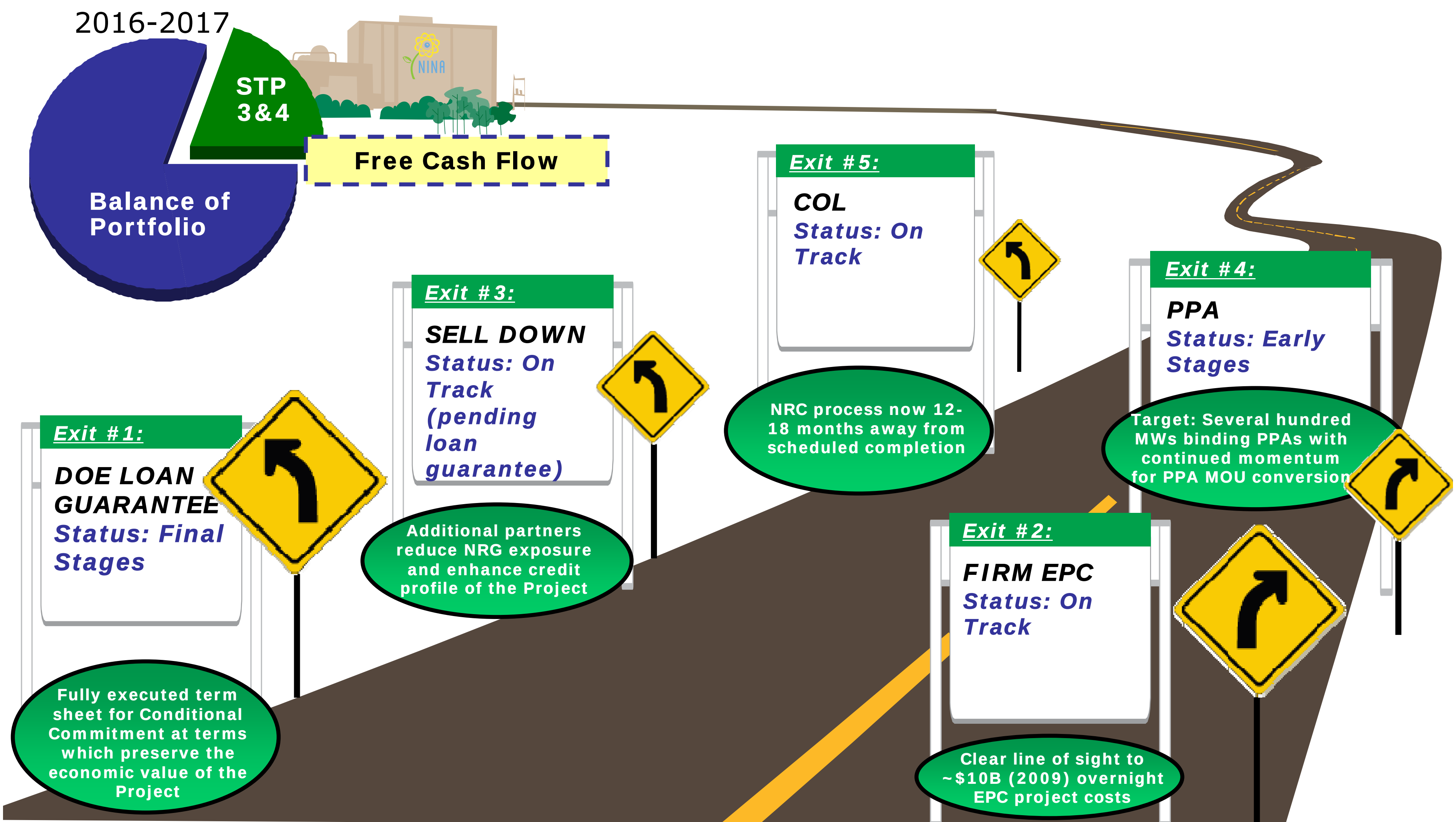
NRG Classic
Baseload
➢ 7,371 MW coal
➢ 1,175 MW nuclear
Load-Following/peaking
➢ 10,642 MW gas
➢ 3,814 MW oil (2,192 MW duel-fuel)
Retail
➢ Reliant (1.5 MM mass, 62,000 C&I customers)

Note: As of 9/30/2010; Excludes international assets of 1,005 MW and pending acquisitions

	Opportunity	NRG Action
Nuclear / Clean Coal →	**Replacement Power** - Very long lead time - High barriers to entry	→ 1. STP 3&4 2. Parish CCS
CCGT →	**Buy not Build** - Baseload in California - Efficient load following in most markets	→ 1. Cottonwood 2. Casco Bay 3. California Plants (all pending)
Reliant →	**Unique Wholesale / Retail Combination** - Countercyclical to commodity prices - De-risked by wholesale	→ 1. Stellar performance 2. Smart technology opportunities

NRG continues to enhance our core portfolio towards our goal of being a multi-fuel, across-the-merit-order, scale generator/retailer in each of our core markets

NINA / STP 3&4: 2011 Milestones/Off-ramps



Significant Milestones with Clearly Demarcated Exit Ramps

STP Loan Guarantee Fee – Understanding the Approach and the Numbers

Loan guarantee fee is supposed to reflect project risks

Structural Differences Between Calvert Cliffs and STP

- Licensing Status
- Construction History
- Construction Method
- EPC Structure
- $ Loan/kW
- Capital Cost/kW
- Off-take Approach
- Ownership Structure
- Operating History

STP 3&4 Project is structured much more on a project finance basis

Near-Term Process for DOE Grant

- Credit Committee (DOE)
- Office of Management and Budget (OMB) Fee
- Credit Review Board (DOE)
- Executive Decision (WH)

Nuclear Conclusion: STP 3&4, and first-mover status in nuclear renaissance, is well worth the current option price (minimal NRG spend) to NRG shareholders

NRG Classic: CCGT and Steam Acquisitions at Substantial Discount to Replacement Cost

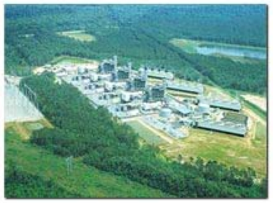
Assets acquired provide strategic fit within
NRG and possess locational, environmental, and technological advantages

Why Dynegy CCGTs?

- Strong economics as new, efficient combined cycle units achieve high dispatch profile
- CA assets poised to benefit from tightening supply/demand balance as once-through cooling leads to retirements
- Positioned to benefit from carbon market uplift (AB32 and RGGI) and gas-firming requirements

Why Dynegy Steam / Oil Assets?

- Required to meet peak demand and to support reliability
- Contracts on steam assets provide stable cash flows for next several years



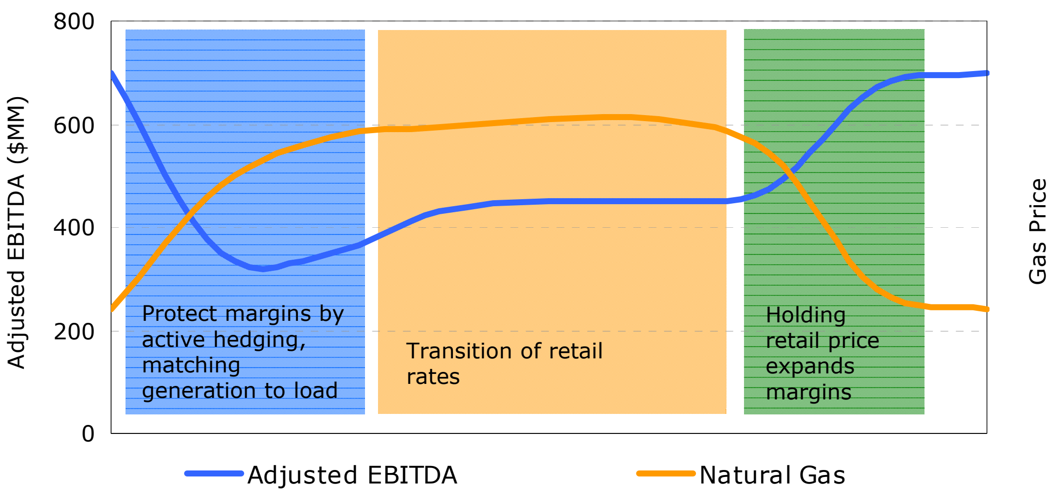
Why Cottonwood?

- Fills gap in regional merit order, enables stabilization and growth of region
- Earns premium from ability to relieve congestion in East Texas region of Entergy control area
- Tolled by NRG providing familiarity with the plant; facilitates contract renewals

Strengthens regional and dispatch diversity to enhance our best-in-class conventional portfolio poised for upside when the market recovers; acts as a rough hedge on environmental risk to incumbent fleet

Retail – Optimize Earnings Through All Cycles

	Rapid increase in gas (example: 2008)	Steady Gas (example: 2009-2011)	Rapid drop in gas (example: late 2008-2009)
Market Behavior	Retail rates increase to follow rise in wholesale prices	Declining retail rates as new contracts signed – eventual return to steady state margins	Retail contract rates held while wholesale prices drop
Margin Drivers (pricing, attrition)	Maintain flat book (same-tenure wholesale hedges against contracted load)	Manage transition to lower retail pricing; rely on premium brand, price differentiation	Capture market opportunities to serve shorter-tenure load at market price
Supply (Benefit of asset-backed portfolio)	Match generation to load to avoid collateral posting for out of money positions as wholesale prices increase	Total wholesale length available as a hedge against price spikes	Transaction cost savings from matching generation and load
Expected EBITDA[1]	**$300-400 MM**	**$400-500 MM**	**$500-$700 MM**



Note: For illustrative purposes; retail lags the wholesale market

Sensitivities Outside the Commodity Cycle

Volume (customer behavior and weather)
+/- 1,000,000 MWh (5% mass volume)
= +/- $20-30 MM

Weather driven margin impacts
+/- $1.00/mmbtu gas on 5% volume
= +/- $8-12 MM

Competitive marketing and prices
+/- 1% change in price
= +/- $50-55 MM

[1] Assuming normal weather- The above adjusted EBITDA scenarios for Reliant Energy are provided across a range of commodity prices and price volatility during unspecified time periods. Therefore, a projection of the associated GAAP measures such as Net Income or Cash from Operations is not available. A GAAP reconciliation of the projected annual 2010 and 2011 adjusted EBITDA to Consolidated Cash from Operations is provided in the Regulation G schedules supplied in the Appendix. In addition, the Appendix also includes a reconciliation of Reliant Energy adjusted EBITDA to Net Income for the nine month period ending September 30, 2010.

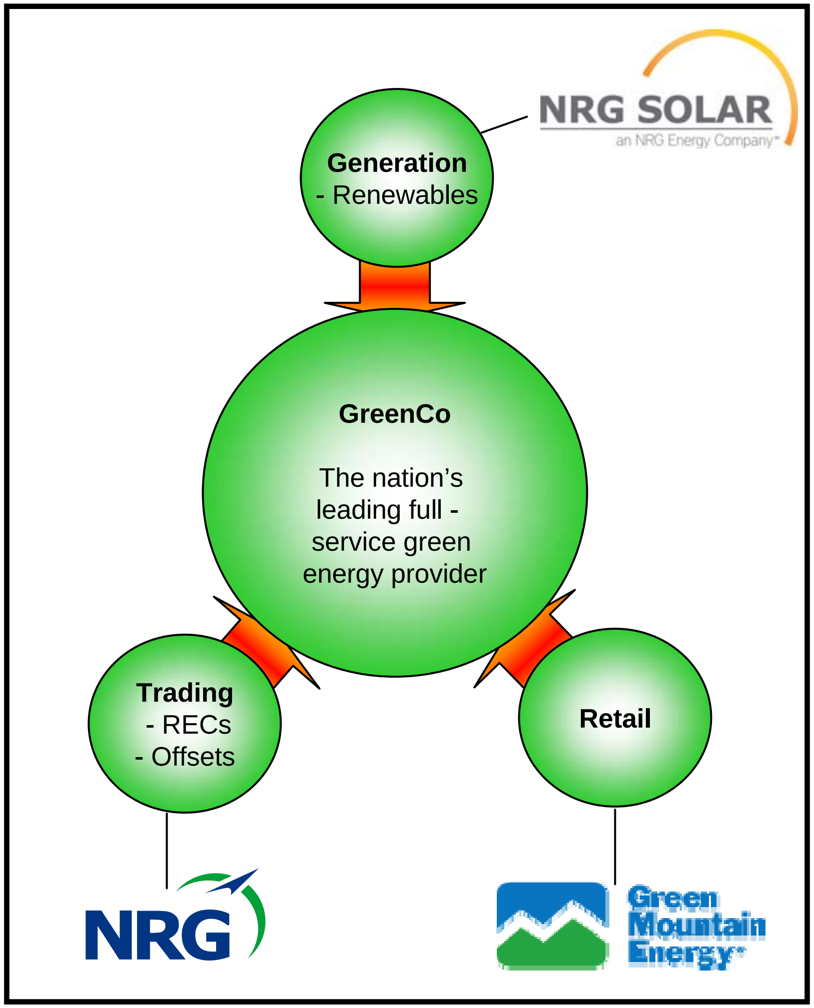
Retail outperforming expectations and demonstrably countercyclical to natural gas

NRG "Greenest": Renewables + Retail = Powerful Combo

Transforming to a post-hydrocarbon provider of green energy solutions

Priorities:

- ☑ Low Carbon Baseload
- ☑ **Renewable Generation…with a concentration in solar**
- ☑ **Green Retail in Competitive Markets**
- ☑ Electric Vehicle Ecosystems
- ☑ Smart grid and other sustainable energy services



★ Moving Towards a Uniquely "All Clean," Fully "All Capable" Green Power Company ★

Green Mountain Energy: NRG's Greenest of the Green

GME: First Mover in Green Retail

- Largest 100% Green residential provider in the US[1] with strong growth in customer count and demand
- Ranked highest in J.D. Power and Associates 2009 Texas Business Retail Electric Provider Satisfaction Study
- Platform for expansion in deregulated markets

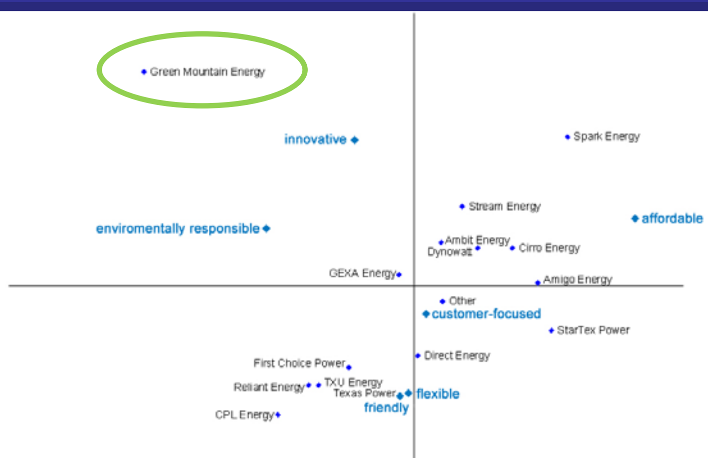
[1]By customer count; EIA 2008 data

Strongest Brand Identification with Cleaner Electricity

Association with Cleaner Electricity	
Green Mountain Energy	**78%**
Reliant	22%
TXU Energy	14%
Stream / Ignite	7%
Amigo	5%
Spark	3%
Gexa	3%
Direct Energy	3%
First Choice	2%
Startex Power	1%
CPL	0%

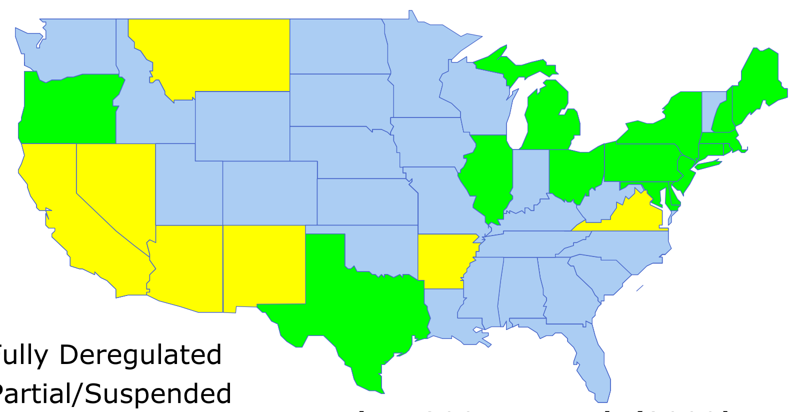
Source: Green Mountain 2009 Texas Brand Tracking Survey. Note: Of those who associated a retail provider with cleaner electricity, these percentages named these companies

A Unique Brand



Source: J.D. Power 2009 TX Residential Satisfaction Study

Market Opportunities: Becoming A National Brand



Fully Deregulated
Partial/Suspended
Regulated
Source: EIA, NREL

Nearly 1,300 MM MWh (2009) total demand in fully deregulated states

The Ultimate Green Energy Brand

Green Mountain Energy: Initial Priorities

1. DGC:	Don't Go Changing who they are
2. Keep on Delivering:	$70 million EBITDA/year at present (no synergies)
3. Targeted Geographic Growth:	Customers in Northeast deregulated markets demand sustainable energy
4. Targeted Product Expansion:	GME is logical sales channel for distributed green energy products
5. Targeted Market Segment Expansion:	GME moving up the C&I chain

Positioning to exceed financial expectations with multifold contributions to the strategic transformation of the company

NRG "Greenest": Solar Development Pipeline

Project	Location	MW	PPA?	Expected COD	Status
Blythe	Blythe, CA	20 MW	20-year	12/2009	Operating
Avenal	Kings County, CA	22.5 MW (net)	20-year	Mid 2011	Under Construction
Ivanpah	Ivanpah, CA	392 MW (gross)	20-25 year	2012-2013	Under Construction
Projected to close (next 6 months)	CA, NM	336 MW	20-25 year	2011-2013	Pre-Construction
Advanced pipeline	CA, NM, AZ	Up to 1000 MW	Yes	2011 to 2014	Permitting/ Approved/ Proposed

Advanced development pipeline—very close to fruition

Economics of Solar Today

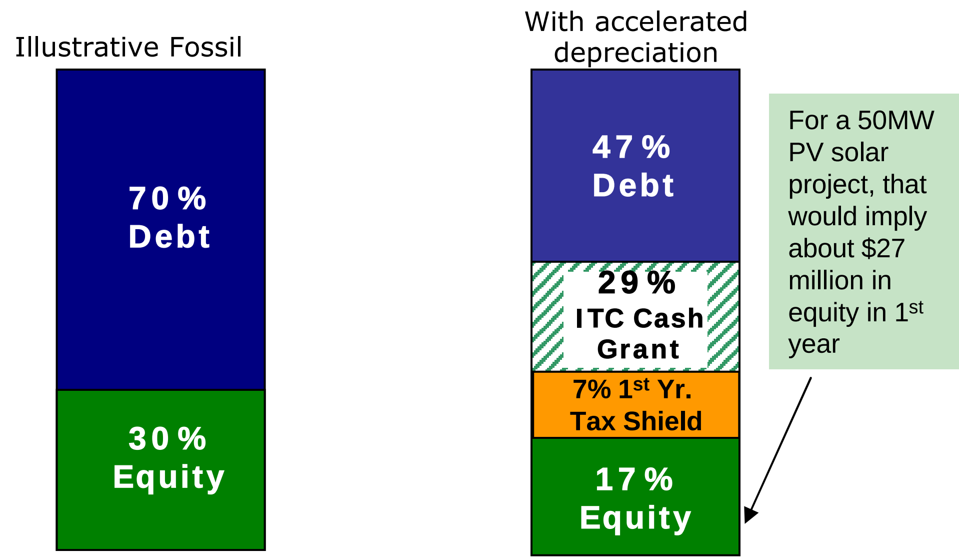
PV vs Solar Thermal

Type of solar technology:	Solar Thermal	Solar PV
Cost / kW	$4500 - $5600/ kW	$3000 - $3900 /kW
Scale	100-500+ MW	kWs-500 MW
Capacity Factor	30-39%	21-30%
Construction	24-36 months	6-36 months
Technology Advantage	Thermal inertia – less disruptive to grid	Can supply energy even with poor solar resource
Non – Recourse Financing (~ 45 -50%)	Requires DOE loan guarantee for newer technologies	Traditional project financing
Levered Returns	Mid-to-high teens	Mid-to-high teens

PLUS

- -No merchant risk
- -Little construction risk
- -Limited O&M requirement
- -Proven technology, particularly PV

Illustrative Fossil vs Renewable Investment



Equity recaptured through cash tax benefits – 55%*

Equity payback through cash tax benefits – 16 years

Equity recaptured through cash tax benefits – 99%*

Equity payback through tax benefits – 3 to 5 years

Virtually no net equity at risk

* NPV of tax benefits @ 9%

Solar: Unbeatable on risk-adjusted return basis

NRG: Six to Nine Month Priorities

1. Improve on 2011 Projected Performance
2. “Fish or Cut Bait” on STP 3&4
3. Integrate Effectively Recently Announced Acquisitions, particularly Green Mountain
4. Deliver on Solar Pipeline Development
5. Launch EV Initiative in Texas
6. Optimize the Wholesale/Retail Combination Benefit both in our Conventional and in our Green Energy Businesses

Operations and Commercial Review

Q3 2010 Operations and Commercial Overview

Operational Performance

- **Safety**
  - Top quartile OSHA recordable rate of 0.88 including Reliant (1.07 without Reliant)
- **Plant Performance**
  - Coal fleet equivalent availability factor (EAF) improves to 94.9% from 92.3%
  - Nuclear (STP) equivalent availability factor at 99.1%
  - Gas/Oil fleet with over 2,500 starts and 98.6% reliability

EPC/Other Performance

- **Environmental Back-end Controls**
  - Indian River Unit 4 environmental retrofits on track for operation in January 2012
- **Repowering**
  - Middletown (200 MW peaker) in construction with COD expected by June 2011
  - El Segundo (550 MW Fast Start CCGT) – PPA approved by CPUC in Oct 2010, COD expected by Summer 2013
- **Other**
  - *FOR*NRG 2.0 on target to meet 2010 goal of $98MM in free cash flow

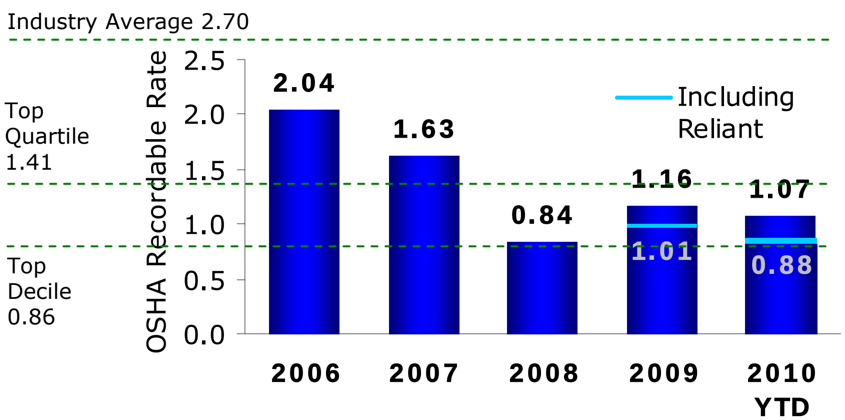
Commercial and Risk Management Activities

- Increased baseload hedge profile for 2011 to 96%
- Effective retail risk management execution through volatile summer months
- Focused on integration of announced acquisitions

Focused on operational excellence and strong commercial execution

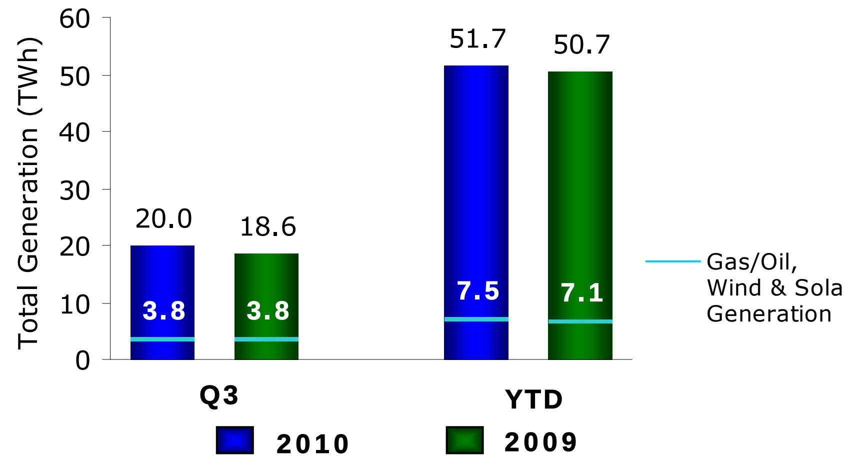
Q3 2010 Operations Update

Safety – Top Quartile Performance[1]

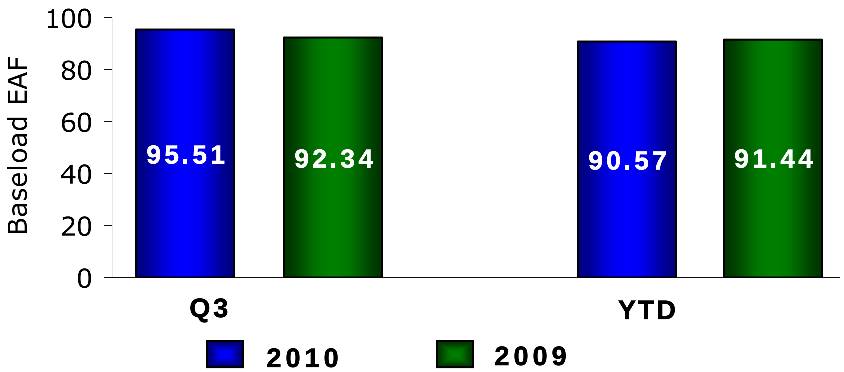


[1] OSHA Top Decile and Top Quartile Rates are Edison Electric Institute Industry Survey

Net Fleet Production (TWh)

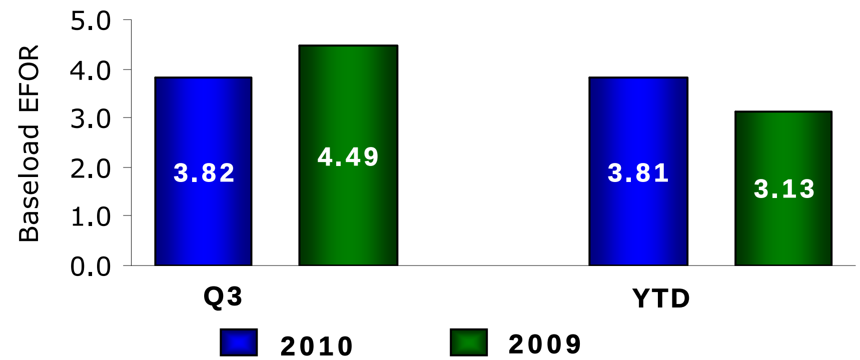


Baseload EAF[2]



[2] Equivalent Availability Factor (EAF) – Measures % of maximum generation available during the period

Baseload EFOR[3]



[3] EFOR- Measures the percent of scheduled operating time that a unit is out of service due to unexpected problems or failures and cannot reach full capability due to forced component or equipment failures

Strong operational performance during critical summer months

Q3 2010 Retail Operations

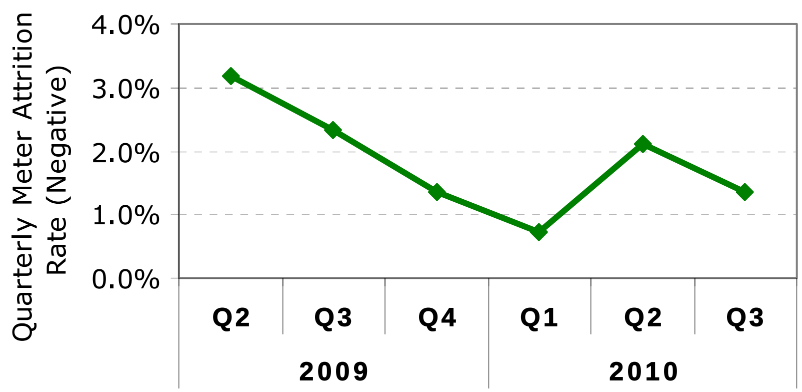
Retail Business Performance

- Mass market segment continues to perform better than expected
  - Improvement in customer attrition and bad debt
  - Sustainable balance of pricing & margins
  - Strong delivery of innovative products
- C&I business continuing to improve
  - Doubled new deal win rate and continued to improve customer renewal rates
  - Continued to deliver client benefits from integration and innovation

Customer Count and Volumes

	Q3 2010	Q2 2010	Q3 2009
Electric Sales Volume (GWh)			
Mass	7,547	5,732	7,776
C&I	7,179	6,683	8,199
Total	14,726	12,415	15,975
Period End Customer Counts (000s of meters)			
Mass	1,468	1,488	1,552
C&I	62	63	66
Total	1,530	1,551	1,618

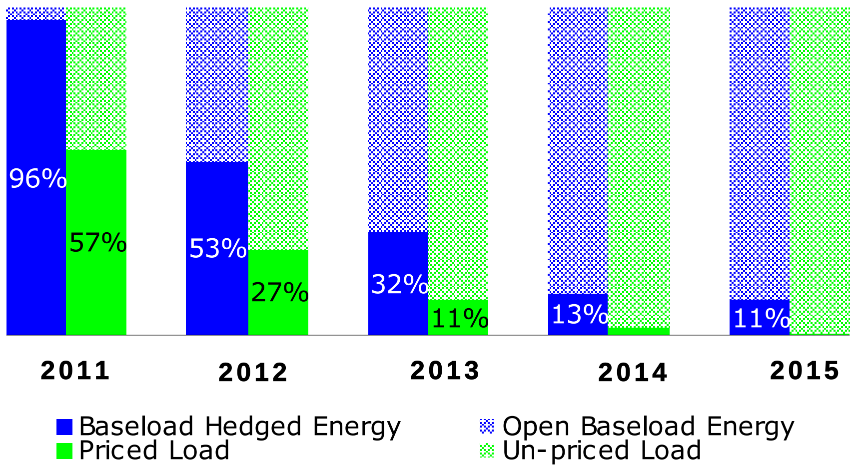
Mass Customer Attrition Rate



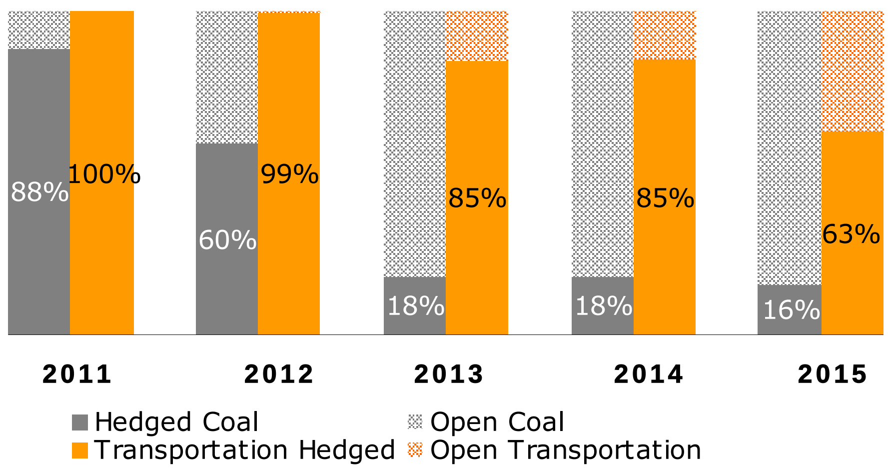
Optimizing margin and customer count by delivering innovative products and excellent customer service

Managing Commodity Price Risk

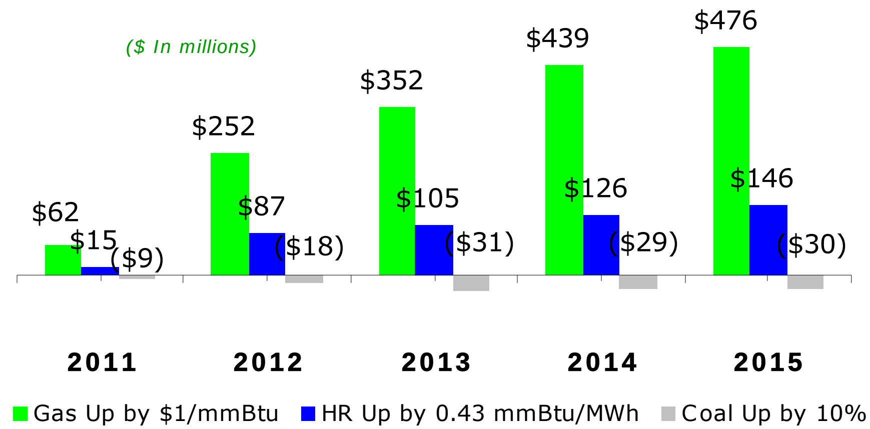
Baseload Generation and Retail Hedge Position(1)(2)



Coal and Transport Hedge Position(1)(4)



Baseload Gas Price, Coal and Heat Rate Sensitivity(1)(3)



Commercial Strategy

- ✓ Assess market to add incremental hedges through options strategy
- ✓ Continue maximizing synergies between wholesale and retail portfolios in Texas
- ✓ Continue focus on origination activities including incremental load following opportunities

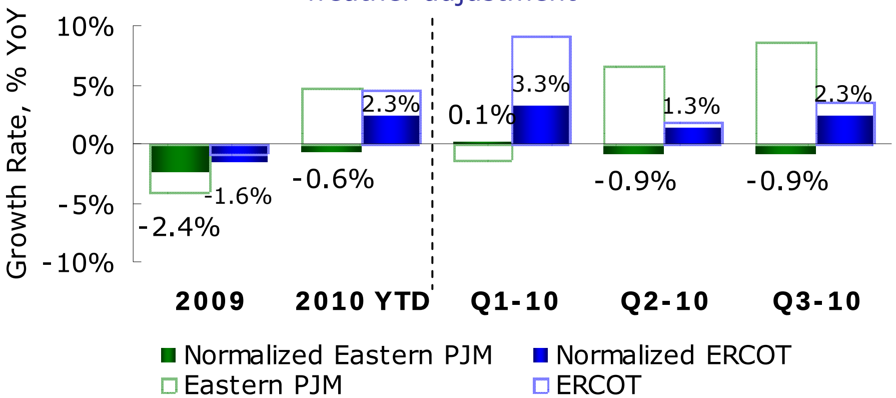
(1) Portfolio as of 10/14/2010; (2) Retail Priced Loads are 100% hedged; (3) Price sensitivity reflects gross margin change from $1/mmBtu gas price, 0.43 mmBtu/MWh heat rate move, and 10% increase in coal prices; (4) Coal position excludes coal inventory that can be used to cover remaining coal requirement in 2011

Continue executing a commercial strategy to maximize value for wholesale/retail combination

Market and Environmental Update

ERCOT Demand Favorable

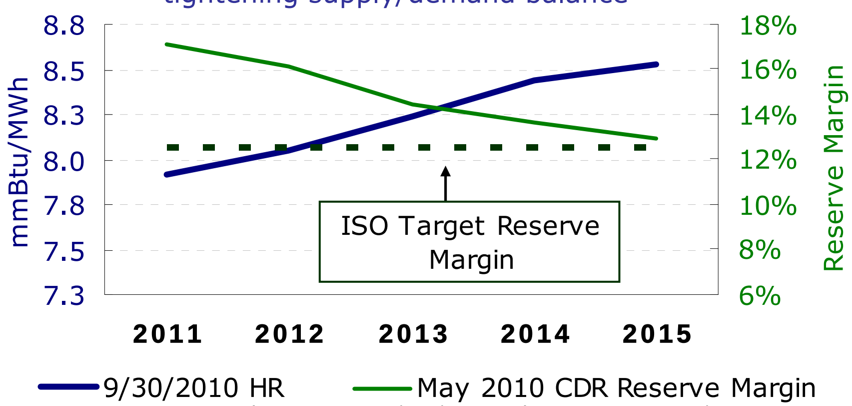
ERCOT demand levels show continuing recovery after weather adjustment



Source: ERCOT, PJM, NRG Research. Eastern PJM refers to the Mid-Atlantic PJM region

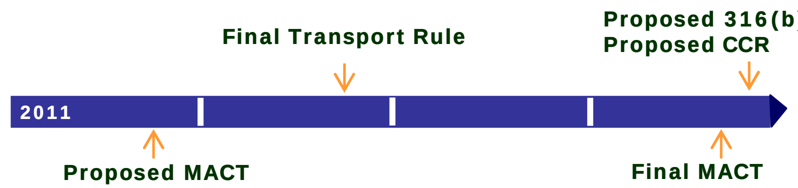
ERCOT Heat Rates remain well supported

Forward heat rate curves suggest markets expect tightening supply/demand balance



Source: ERCOT May 2010 CDR (Capacity, Demand, and Reserves) Report, NRG Research. Note: Heat rates=RTC Houston vs Henry Hub

Environmental Update – More Clarity in 2011



Current environmental Capital Plan of ~$700 million (2011-2014) tailored to meet expected environmental regulation

- **Release of proposed Transportation Rule**
  - No additional capital expenditures required
- **MACT**
  - Considered under current plan but incremental capital required under worst acid gas case
- **Proposed CA and NY 316(b) policy**
  - Alternatives to cooling towers & repowering for compliance
- **Proposed Coal Ash Regulations**
  - No wet fly ash disposal at NRG

Continued strong fundamentals in ERCOT market and manageable environmental requirements from future regulations

Near Term Goals

- Focus on safety, operational and commercial excellence
- Advocate for sound environmental regulations and optimize investment as rules gain clarity
- Assess market for additional hedging opportunities
- Drive construction projects toward completion on time and on budget
- Integration of announced acquisitions

Financial Review

Financial Summary

- ☑ Strong Quarterly Results
  - $777 million of adjusted EBITDA
  - $209 million of adjusted EBITDA from Reliant Energy

- ☑ YTD Results
  - $2,071 million of adjusted EBITDA
  - $594 million of adjusted EBITDA from Reliant Energy

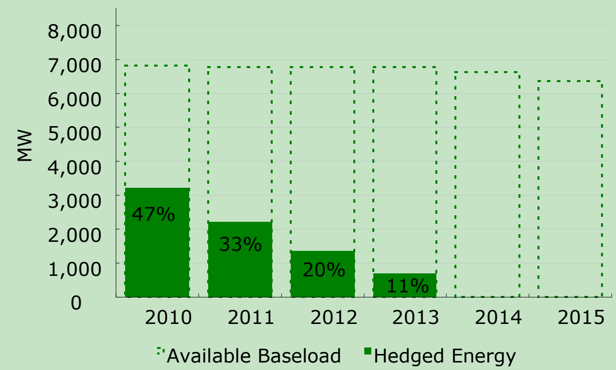
- ☑ Liquidity of $4,755 million in support of our capital structure and capital allocation needs
  - ☑ Completed $180 million 2010 share repurchase program
  - ☑ $1,100 million of 8.25% Senior Notes
  - ☑ $190 million tax-exempt financing for Indian River Environmental CapEx
  - ❑ Acquisition of assets
    - Dynegy Assets - $1,363 million
    - Cottonwood - $525 million
    - Green Mountain Energy - $350 million

Liquidity

$ in millions	Sep 30, 2010	Dec 31, 2009
Cash and Cash Equivalents	$ 3,447	$ 2,304
Restricted Cash	19	2
Total Cash	**3,466**	**2,306**
Funds Deposited by Counterparties	457	177
Total Cash and Funds Deposited	**$ 3,923**	**$ 2,483**
Synthetic LC Availability	**450**	**583**
Revolver Availability	**839**	**905**
Total Liquidity	**$ 5,212**	**$ 3,971**
Less: Collateral Funds Deposited	(457)	(177)
Total Current Liquidity	**$ 4,755**	**$ 3,794**

Beginning cash	**$ 2,306**
Cash provided by operating activities	1,141
Debt Proceeds ($1.1B Senior Notes, Thermal $100M)	1,252
Proceeds from renewable energy tax grants	102
Debt Payments (Term Loan B $247M,CSF $190M)	(529)
CapEx, excl. NINA	(274)
Payment for treasury stock	(180)
NINA CapEx, net	(179)
Acquisitions, net of debt acquired	(142)
Other	(31)
Ending cash	**$ 3,466**

Lien Structure* (MWs & %) @ 9/30/2010



* Represents 80% of energy hedged under the Lien Structure for rolling 60 months and 60% for the following 12 months.

Lien Structure provides additional hedging liquidity:

Total 166 TWhs of hedging capacity available 2011-2015

Ample liquidity to complete pending acquisitions

2010 Guidance

$ in millions	11/4/2010 Guidance	8/2/2010 Guidance
Wholesale	$1,825-$1,850	$1,800-$1,850
Retail	$675-$700	$650-$700
Consolidated Adjusted EBITDA	$2,500-$2,550	$2,450-$2,550
Free Cash Flow – before Growth	$1,198-$1,248	$1,098-$1,198
Free Cash Flow	$699-$749	$824-$924

Note: Original August 2nd FCF guidance of $816-$916 million was adjusted upward by $8 million to reflect actual NRG capital calls to NINA

Free Cash Flow – before Growth Yield

24% - 25%

Note: Cash Flow Yield based on common stock share price of $20.04 as of November 3, 2010

Free Cash Flow – before Growth Per Share

$4.77 - $4.97

Note: Calculated by adding back preferred dividends and dividing by the weighted average number of common diluted shares of 253 million

Adjusted EBITDA guidance raised to the upper end of prior guidance

2011 Guidance

$ in millions	11/4/2010 Guidance
Wholesale	$1,350-$1,450
Retail	$480-$570
Green Mountain	$70-80
Consolidated Adjusted EBITDA	$1,900-$2,100
Free Cash Flow – before Growth	$950-$1,150
Free Cash Flow	$550-$750

Wholesale Drivers

- ✓ Includes acquisitions of Dynegy assets and Cottonwood
- ✓ Lower overall hedged prices across the portfolio
- ✓ Lower capacity prices in the Northeast region
- ✓ Cost control measures in place in response to declining commodity market

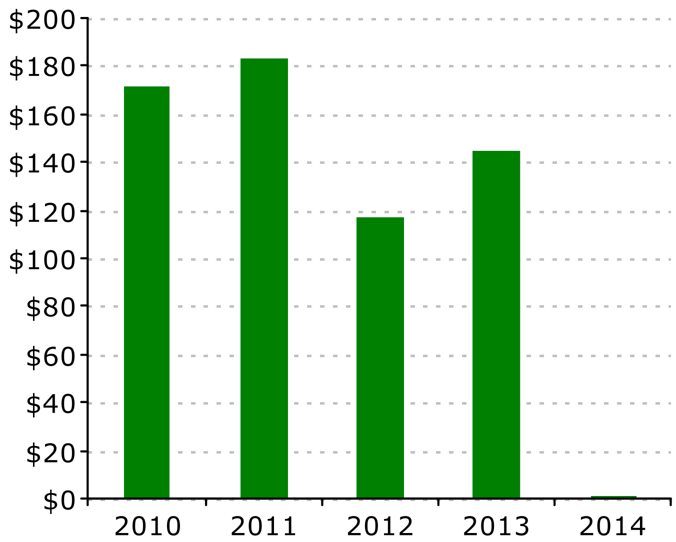
Retail Drivers

- ✓ Competitive market prices lead to lower margins on the Mass business
- ✓ Stabilization of customer count
- ✓ Normal weather

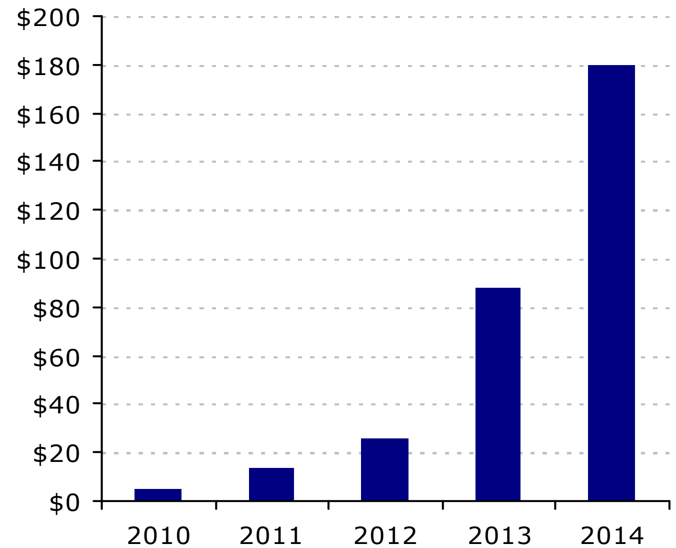
NRG generates a billion dollars of free cash flow before growth investments

Solar – Meaningful EBITDA Contribution

Equity Contributions
(Net of Cash Grant)



EBITDA[1]



[1] Includes EBITDA contribution from our existing Blythe asset

Note: EBITDA reconciliation shown in Reg. G Schedules

Construction pipeline:

- ~500MW
- NRG Equity (net of Cash Grant) = $600M
- EBITDA = $175M

~$600M net equity contributed over next four years resulting in $175M+ annual EBITDA contribution

2011 Projected Cash Position

$ in millions		Total Cash & Cash Equivalents
September 30, 2010		**$ 3,447**
Q4 2010 Free Cash Flow[1]	86	
2011 Free Cash Flow[1]	650	
Acquisitions[2]	(2,238)	
Debt Repayments	(460)	
Year-end 2011		**$ 1,485**

2011 Capital Allocation

- Projected cash balance of $1,485 million
- Targeted Cash Balance of $700 million
  - Working Capital, margin calls and construction costs
- In 2011 deployable capital of $785 million is available for:
  - Share Repurchases
  - Investment in additional high return growth opportunities
    - Repowering
    - Solar
    - Other Green opportunities

[1] Free Cash Flow represents the midpoint of 2010 full year guidance of $699-$749M less year-to-date FCF of $638M while 2011 FCF is the midpoint of the guidance range of $550-$750M

[2] Acquisition assumes $1,363M for Dynegy assets, $525M for Cottonwood, $350M for Green Mountain

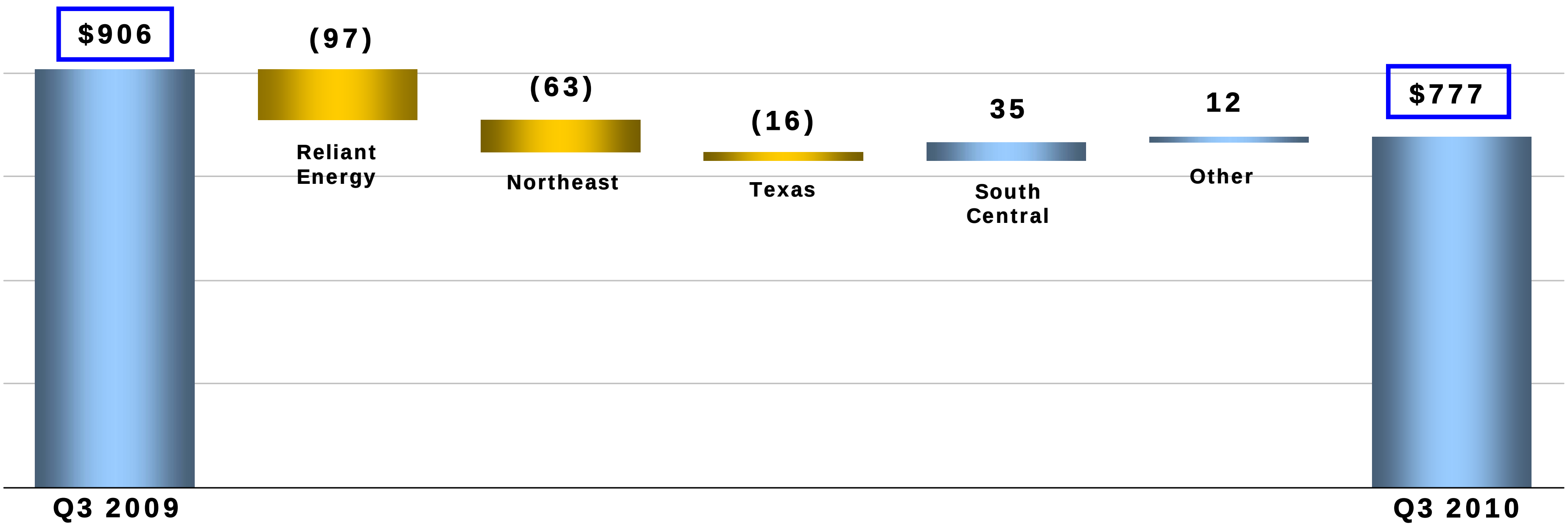
2011 projected cash balance of $1.5 billion enables NRG to have a balanced Capital Allocation Plan

Closing Remarks and Q&A

Appendix

Q3 Adjusted EBITDA – 2010 vs. 2009

$ in millions



Reliant Energy

- Mass gross margins declined 17% driven by lower unit margins on acquired and renewal customers
- Lower mass volumes driven by lower customer count

Northeast

- Lower energy margins due to lower hedged prices in 2010 compared to 2009
- 37% increase in generation due to warmer than expected weather in 2010 and increased merchant energy prices
- Decrease in capacity revenues mainly due to the expiration of the RMR contracts in NEPOOL on May 31, 2010

Texas

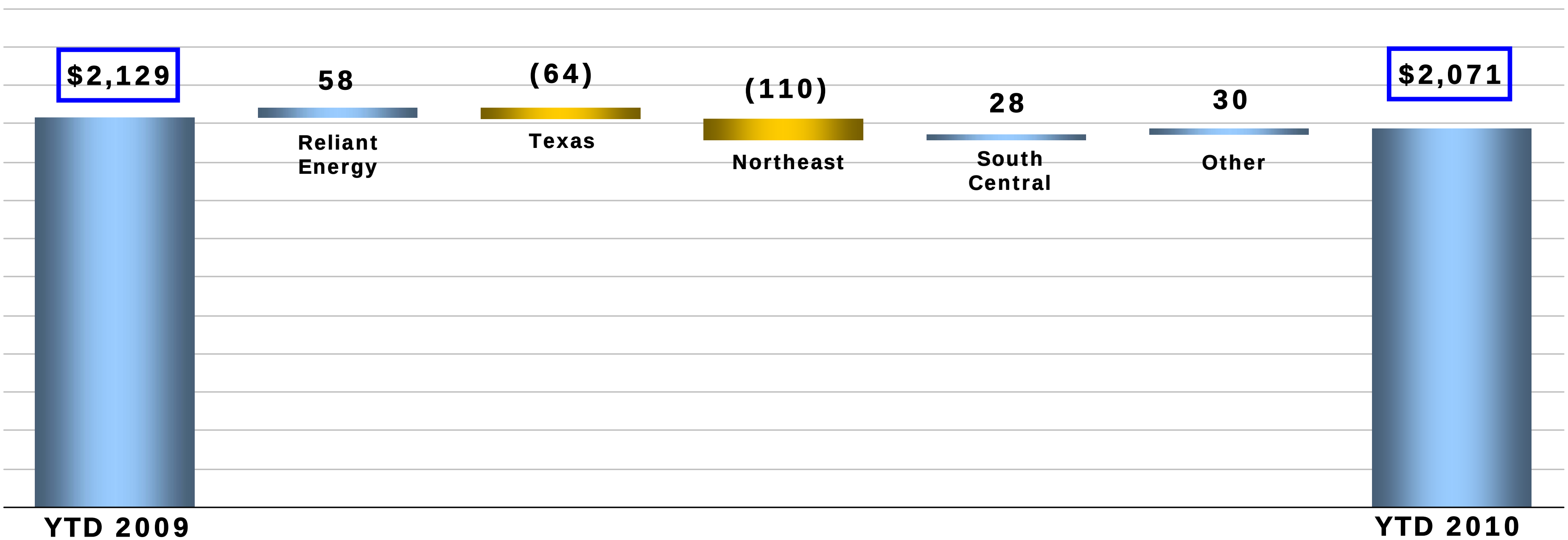
- 20% increase in fuel costs driven by a new transportation contract at Parish Coal and a higher average cost of natural gas in Q3 2010 vs. Q3 2009
- 5% increase in generation due to higher nuclear generation and the addition of the Langford and South Trent wind farms
- Lower major maintenance costs at STP plus a prior year sales & use tax refund

South Central

- Contract revenue favorable due to the addition of a new contract with a regional municipality and increased sales to the legacy contracts

YTD Adjusted EBITDA – 2010 vs. 2009

$ in millions



Reliant Energy

- Reliant Energy acquired May 1, 2009; excluding Jan-April 2010, EBITDA lower by ($169M)
- Mass revenue rates lower due to a combination of price reductions enacted following the acquisition and lower pricing plans for new and renewal customers consistent with competitive offers

Texas

- Lower energy margins driven by higher coal transportation costs
- Higher major maintenance costs due to timing of STP refueling outage

Other

- Corporate - gain on sale of Padoma
- International – realized foreign exchange gains

Northeast

- Cancellation of environmental work due to planned retirement of Indian River unit 3
- Lower energy margins due to a decrease of 31% on hedged prices in 2010 compared to 2009
- Decrease in capacity revenue as lower RMR revenue was partially offset by higher prices in PJM and NY

South Central

- Increased volume on contract sales of 13% driven by the addition of a new contract with a regional municipality which also led to a 19% increase in the average realized energy price
- Unrealized losses in 2009 related to forward physical power sales

Capital Expenditures – 2010 YTD Results

$ in millions		Maintenance		Environmental		Growth Investments incl. ***Repowering*** **NRG**		Total
Capital Expenditures, excluding NINA:								
Northeast	$	9	$	135	$	1	$	145
Texas		58		-		-		58
South Central		10		-		-		10
West		5		-		12		17
Retail		7		-		-		7
IDC/Other		39		-		16		55
Accrued CapEx	**$**	**128**	**$**	**135**	**$**	**29**	**$**	**292**
Accrual impact		(9)		(3)		(6)		(18)
Total Cash CapEx	**$**	**119**	**$**	**132**	**$**	**23**	**$**	**274**
GenConn Equity Investment, net		-		-		55		55
Project Funding:								
Dunkirk bonds		-		(6)		-		(6)
Total Capital Expenditures, net and Investments	**$**	**119**	**$**	**126**	**$**	**78**	**$**	**323**

Capital Expenditures – 2010 Full Year Guidance

$ in millions	Maintenance	Environmental	Growth Investments incl. *Repowering* NRG	Total
Capital Expenditures, excluding NINA:				
Northeast	$ 18	$ 186	$ 1	$ 205
Texas	105	-	-	105
South Central	18	-	-	18
West	9	-	166	175
Retail	14	-	-	14
IDC/Other	64	7	33	104
Accrued CapEx	**$ 228**	**$ 193**	**$ 200**	**$ 621**
Accrual impact	-	-	-	-
Total Cash CapEx	**$ 228**	**$ 193**	**$ 200**	**$ 621**
GenConn Equity Investment, net	-	-	61	61
Avenal Equity Investment	-	-	16	16
Ivanpah Equity Investment, net	-	-	44	44
Project Funding:				
Dunkirk bonds	-	(6)	-	(6)
Indian River bonds	-	(92)	-	(92)
Total Capital Expenditures, net and Investments	**$ 228**	**$ 95**	**$ 321**	**$ 644**

Capital Expenditures – 2011 Guidance

$ in millions	Maintenance	Environmental	Growth Investments incl. *Repowering* NRG	Total
Capital Expenditures, excluding NINA:				
Northeast	$ 58	$ 163	$ -	$ 221
Texas	96	-	-	96
South Central	26	15	-	41
West	15	-	471	486
Retail	15	-	-	15
Electric Vehicles	-	-	13	13
IDC/Other	36	9	40	85
Accrued CapEx	**$ 246**	**$ 187**	**$ 524**	**$ 957**
Accrual impact	-	-	-	-
Total Cash CapEx	**$ 246**	**$ 187**	**$ 524**	**$ 957**
GenConn Equity Investment, net	-	-	60	60
Ivanpah Equity Investment, net	-	-	177	177
Project Funding:				
El Segundo	-	-	(207)	(207)
Solar	-	-	(211)	(211)
Indian River bonds	-	(76)	-	(76)
Total Capital Expenditures, net and Investments	**$ 246**	**$ 111**	**$ 343**	**$ 700**

Adjusted EBITDA by Region

$ in millions

Segment	Three Months Ended 9/30/10	Three Months Ended 9/30/09	Three Months Ended Change	Nine Months Ended 9/30/10	Nine Months Ended 9/30/09	Nine Months Ended Change
Retail	$ 209	$ 306	$ (97)	$ 594	$ 536	$ 58
Texas	388	404	(16)	1,004	1,068	(64)
Northeast	105	168	(63)	281	391	(110)
South Central	39	4	35	85	57	28
West	24	24	-	45	40	5
International	12	9	3	56	47	9
Thermal	9	4	5	20	17	3
Corporate	(9)	(13)	4	(14)	(27)	13
Consolidated NRG	**$ 777**	**$ 906**	**$ (129)**	**$ 2,071**	**$ 2,129**	$ (58)

Note: Detailed adjustments by region are shown in Reg. G Schedules

Q3 2010 Generation Sold & Availability

(MWh in thousands)	2010	2009	Change	%	2010 EAF[1]	2010 NCF[2]	2009 EAF[1]	2009 NCF[2]
Texas	13,646	13,979	(333)	(2)	93%	54%	92%	52%
Northeast	3,776	2,508	1,268	51	93	22	93	15
South Central	3,458	3,243	215	7	97	48	95	43
West	100	289	(189)	(65)	98	6	93	12
Total	**20,980**	**20,019**	**961**	**5**	**94%**	**39%**	**93%**	**36%**
Texas Nuclear	2,536	2,368	168	7	99%	98%	92%	91%
Texas Coal	8,104	7,695	409	5	96	88	92	84
NE Coal	2,561	1,970	591	30	93	66	94	44
SC Coal	2,976	2,632	344	13	95	91	92	81
Baseload	**16,177**	**14,665**	**1,512**	**10**	**96%**	**86%**	**92%**	**77%**
Solar	13	-	13	n/m	n/a	n/a	n/a	n/a
Wind	222	59	163	n/m	n/a	27	n/a	23
Intermittent	**235**	**59**	**176**	**n/m**	**n/a**	**27%**	**n/a**	**23%**
Oil	70	40	30	75	97%	4%	96%	1%
Gas - Texas	2,133	2,412	(279)	(12)	89	18	91	19
Gas - NE	812	498	314	63	92	9	90	5
Gas - SC	72	95	(23)	(24)	99	2	98	3
Gas - West	87	289	(202)	(70)	98	6	93	12
Intermediate/Peaking	**3,174**	**3,334**	**(160)**	**(5)**	**93%**	**11%**	**93%**	**11%**
Purchased Power	**1,394**	**1,961**	**(567)**	**(29)**				
Total	**20,980**	**20,019**	**961**	**5**				

[1] Equivalent Availability Factor

[2] Net Capacity Factor

2010 Sept. YTD Generation Sold & Availability

(MWh in thousands)	2010	2009	Change	%	2010 EAF[1]	2010 NCF[2]	2009 EAF[1]	2009 NCF[2]
Texas	36,489	36,485	4	0	91%	48%	89%	48%
Northeast	8,509	6,779	1,730	26	91	15	90	13
South Central	9,858	9,204	654	7	90	43	91	42
West	197	365	(168)	(46)	87	5	83	8
Total	**55,053**	**52,833**	**2,220**	**4**	**91%**	**33%**	**89%**	**33%**

(MWh in thousands)	2010	2009	Change	%	2010 EAF[1]	2010 NCF[2]	2009 EAF[1]	2009 NCF[2]
Texas Nuclear	7,004	7,493	(489)	(7)	91%	91%	98%	97%
Texas Coal	22,839	22,469	370	2	92	84	92	83
NE Coal	6,183	5,683	500	9	91	51	87	43
SC Coal	7,941	7,665	276	4	85	82	90	79
Baseload	**43,967**	**43,310**	**657**	**2**	**91%**	**78%**	**91%**	**76%**
Solar	41	-	41	n/m	n/a	n/a	n/a	n/a
Wind	660	241	419	n/m	n/a	31	n/a	27%
Intermittent	**701**	**241**	**460**	**n/m**	**n/a**	**31%**	**n/a**	**27%**
Oil	96	122	(26)	(21)	95%	2%	93%	1%
Gas - Texas	4,363	4,324	39	1	90	12	86	12
Gas - NE	1,241	974	267	27	90	4	89	3
Gas - SC	115	154	(39)	(25)	95	1	92	2
Gas - West	156	365	(209)	(57)	87	5	83	8
Intermediate/Peaking	**5,971**	**5,939**	**32**	**1**	**91%**	**7%**	**88%**	**7%**
Purchased Power	**4,414**	**3,343**	**1,071**	**32**				
Total	**55,053**	**52,833**	**2,220**	**4**				

[1] Equivalent Availability Factor

[2] Net Capacity Factor

Fuel Statistics

Domestic	3rd Quarter 2010	3rd Quarter 2009	Year to Date 2010	Year to Date 2009
Cost of Gas ($ / mmBTU)	$ 4.55	$ 3.36	$ 4.76	$ 3.66
Coal Consumed (mm Tons)	8.7	7.3	23.3	22.3
PRB Blend	80%	78%	82%	79%
Northeast	74%	73%	71%	72%
South Central	100%	100%	100%	100%
Texas	75%	74%	79%	74%
Coal Costs ($ / mmBTU)	$ 2.17	$ 1.89	$ 2.08	$ 1.86
Northeast	3.10	2.83	3.05	2.93
South Central	1.97	1.91	1.90	1.92
Texas	1.98	1.67	1.90	1.60
Coal Costs ($ / Tons)	$ 35.57	$ 30.73	$ 34.11	$ 30.10
Northeast	59.40	54.09	58.53	56.14
South Central	32.34	31.86	31.40	30.00
Texas	31.01	26.03	30.12	23.37

Q3 Operating Revenues

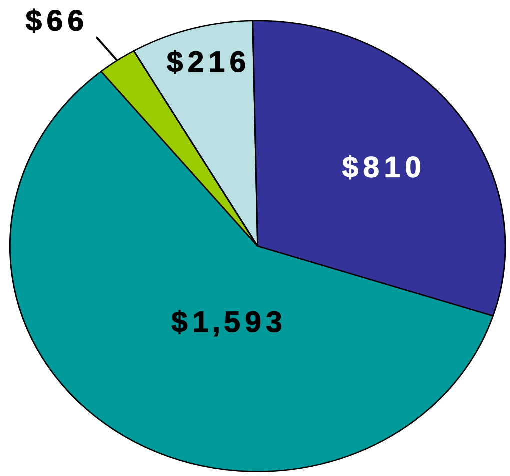
$ in millions

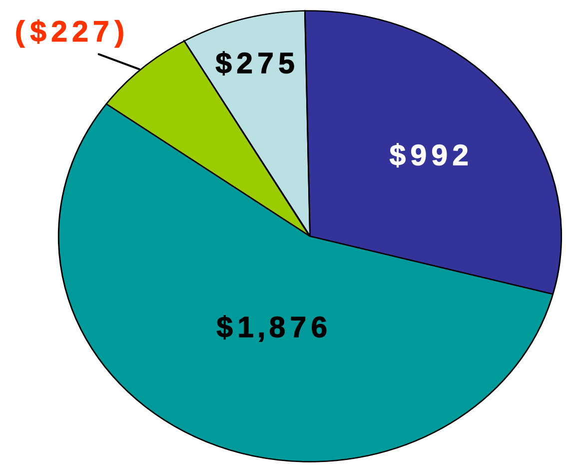
Q3 10: $2,685 MM

Q3 09: $2,916 MM

By Type

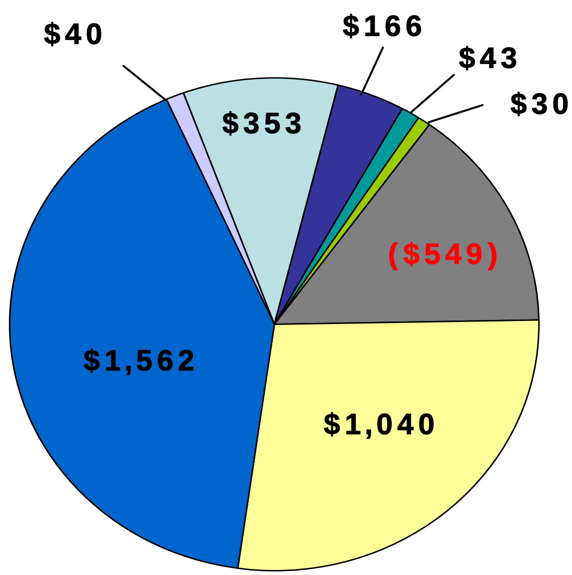
Capacity
Retail
Energy
Other

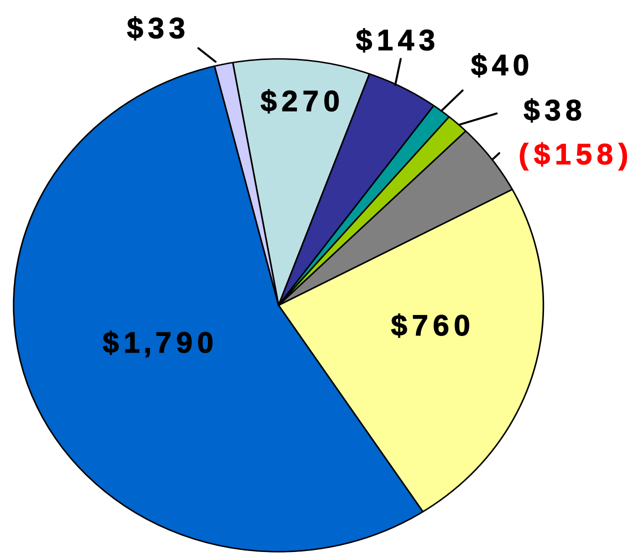




By Segment

Texas
Retail
Northeast
South Central
West
International
Thermal
Corp./Eliminations

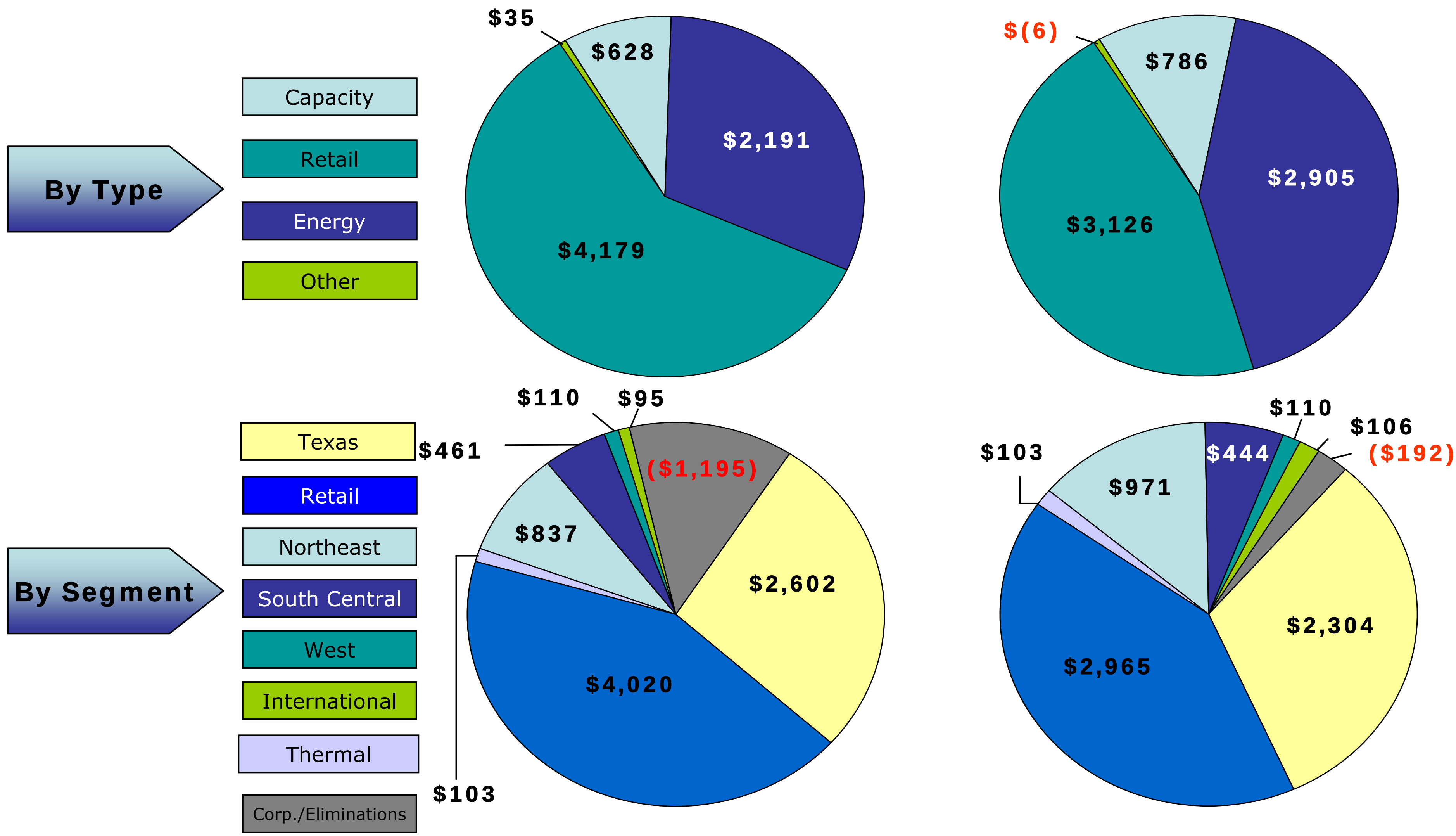




2010 Sept. YTD Operating Revenues

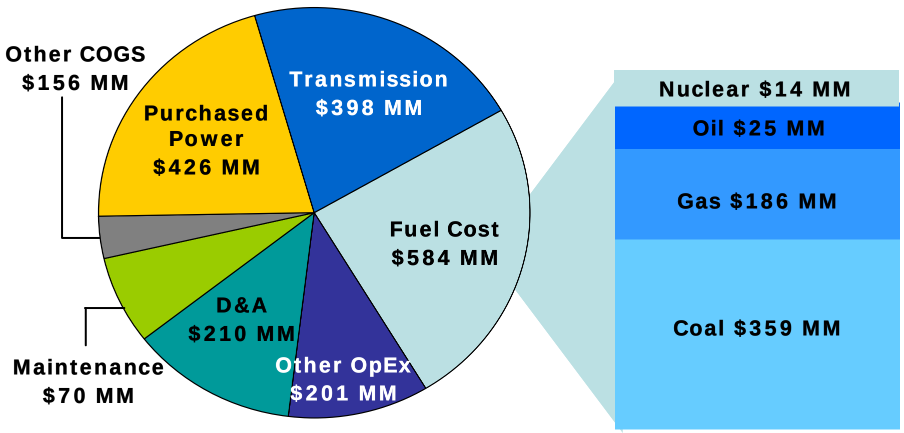
$ in millions

YTD 10: $7,033 MM | **YTD 09: $6,811 MM**

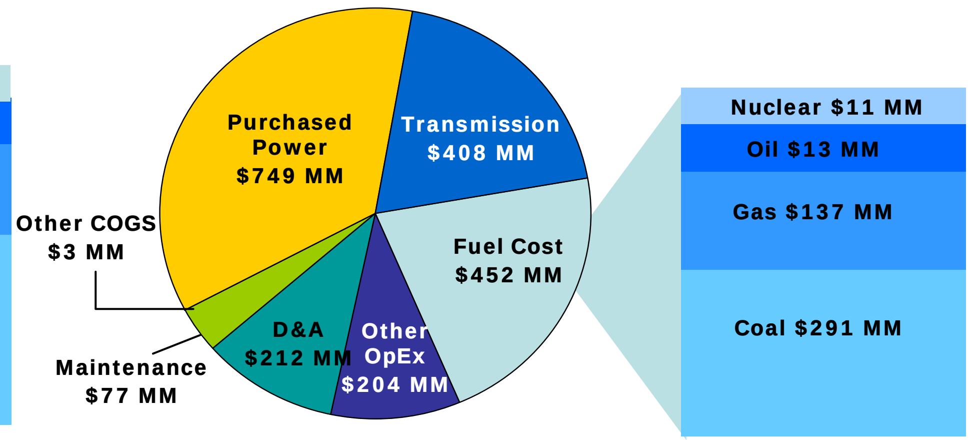


Operating Expenses and Depreciation

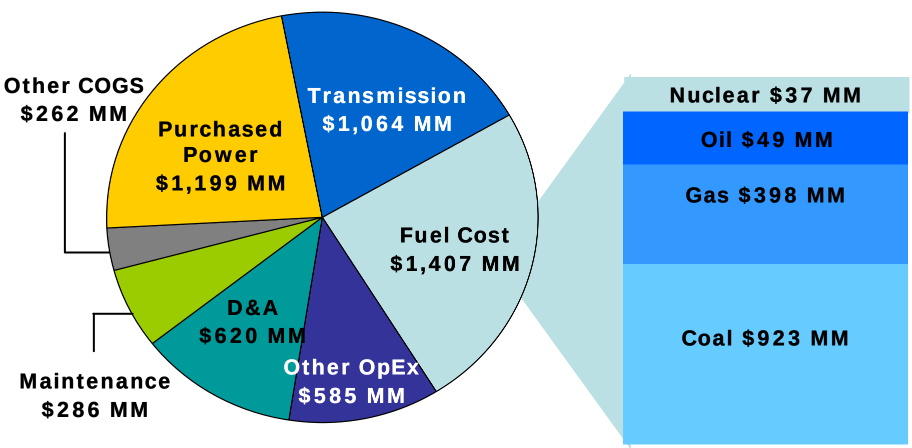
Q3 10: $2,045 MM



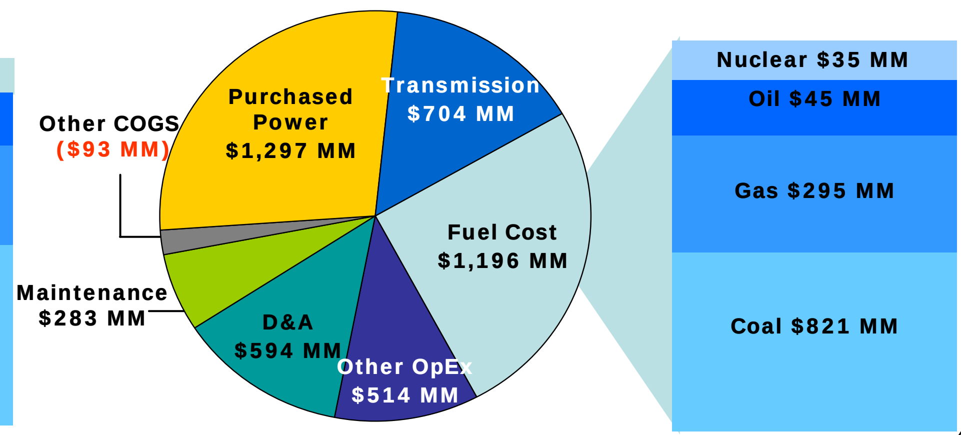
Q3 09: $2,105 MM



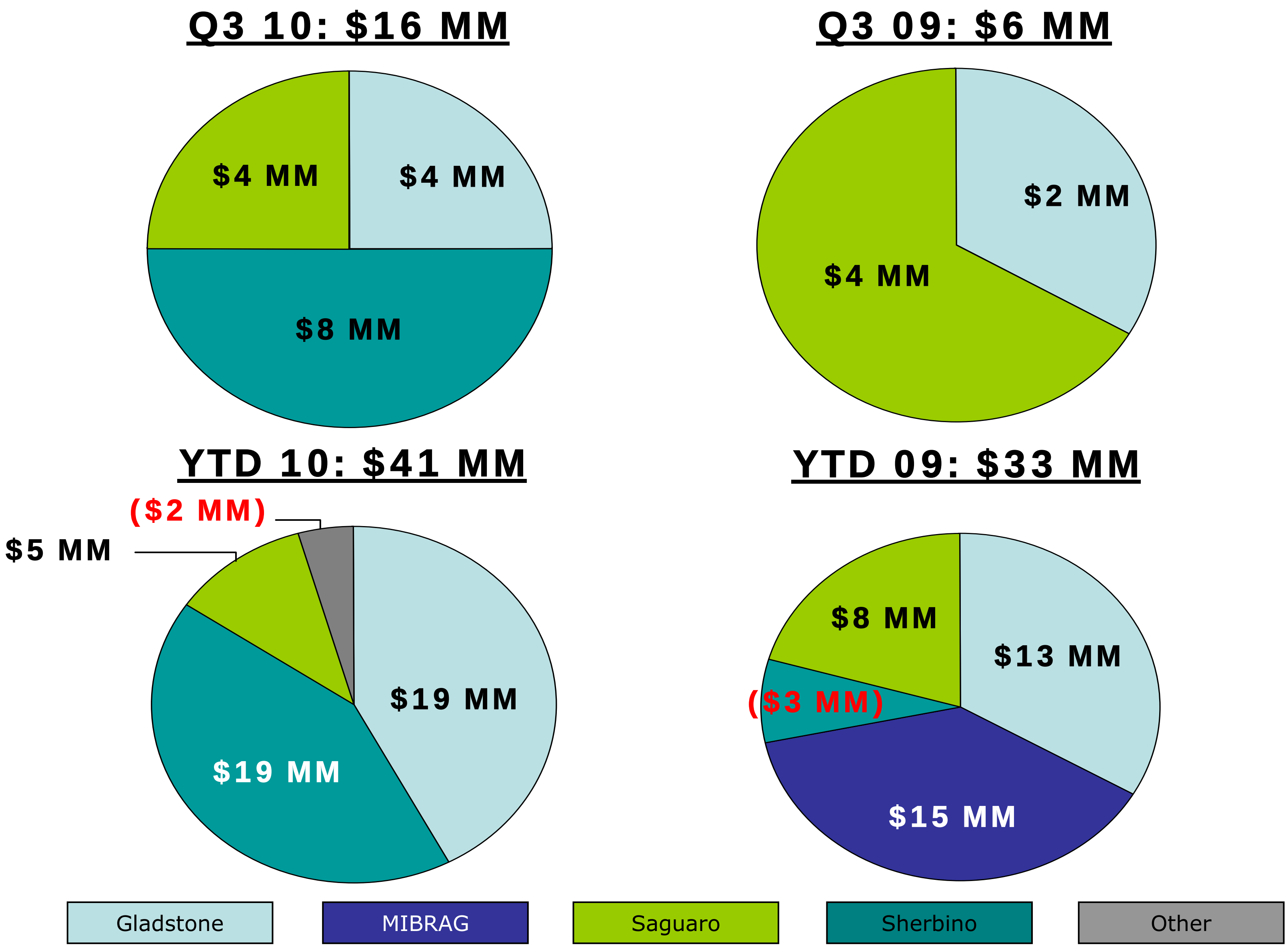
YTD 10: $5,423 MM



YTD 09: $4,495 MM



Equity Earnings



Restricted Payments (RP) Capacity 101

Indentures[1]

Based on GAAP net income and currently driven RP capacity limitations; Governed by increases in net income.

Adders:
+ Issuance of stock
+ Issuance of convertible preferred

Deductions:
– Payments of dividends
– Repurchases of stock
– Payment of dividends on new preferred

Items that do not increase basket
- ➢ Asset Sales (Gains or Losses)

Growth Parameter
- ➢ 50% of Net Income

Credit Agreement

Based on corporate cash flows[2]

Adders:
+ Issuance of stock for cash proceeds
+ Issuance of convertible preferred

Deductions:
– Payments of dividends
– Repurchases of stock
– Payment of dividends on new preferred

Items that do not increase basket
- ➢ Asset Sales

Growth Parameter
- ➢ Currently 50% of cash flow, dependent on Debt/EBITDA

[1] Excluding 8.5% senior notes due 2019 and 8.25% senior notes due 2020
[2] Cash flow defined as: cash from operations, less maintenance and environmental CapEx, less net investment in growth CapEx, less principal payments

Capacity Revenue Sources: Generation Asset Overview

In addition to our baseload hedging program, NRG revenues and free cash flows benefit from capacity sources originating from either market clearing capacity prices, Reliability Must Run (RMR)/Resource Adequacy (RA) contracts, power purchase agreement (PPA) contracts, and tolling arrangements. While ERCOT (Texas) region does not have a capacity market, Texas capacity revenues reflect bilateral transactions. Prior to NRG's acquisition of Texas Genco, the Public Utility Commission of Texas (PUCT) regulations required that Texas generators sell 15% of their capacity by auction at reduced rates. In March 2006, the PUCT accepted NRG's request to no longer participate in these auctions and that capacity is now being sold in the merchant market. In addition to the PUCT mandated auctions, the prior owners of Texas Genco also participated in voluntary auctions. These capacity contracts expired in 2009. In South Central,[3] NRG earns significant capacity revenue from its long-term contracts. As of September 30, 2010, NRG had long-term all-requirements contracts with 10 Louisiana distribution cooperatives with initial terms ranging from ten to twenty-five years. Of the ten contracts, seven expire in 2025 and account for 53% of contract load, while the remaining three expire in 2014 and comprise 42% of contract load. During 2009, NRG successfully executed all-requirements contracts with three Arkansas municipalities with service start dates as early as April 2010. These new contracts account for over 500 MW of total load obligations for NRG and the South Central region. In addition, NRG has certain long-term contracts with the South Mississippi Electric Power Association and Southwestern Electric Power Company, which collectively comprise an additional 5% of region's contract load requirement. The table below reflects the plants and relevant capacity revenue sources for the Northeast, West and Thermal business segments:

Region and Plant	Zone	MW	Sources of Capacity Revenues: Market Capacity, Reliability Must Run (RMR), PPA, and Tolling Arrangements	Tenor
NEPOOL (ISO NE):				
Devon	SWCT	135	LFRM/FCM[1]	
Connecticut Remote Turbines	SWCT	145	LFRM/FCM[1]	
Montville	CT – ROS	500	RMR/FCM[2]	RMR until June 2010
Somerset Power	SE – MASS	16[4]	LFRM/FCM[1]	Decommissioned
Middletown	CT – ROS	770	RMR /FCM[2]	RMR until June 2010
Norwalk Harbor	SWCT	340	RMR/FCM[2]	RMR until June 2010
PJM:				
Indian River	PJM - East	660[5]	DPL- South	
Vienna	PJM – East	170	DPL- South	
Conemaugh	PJM – West	65	PJM- MAAC	
Keystone	PJM – West	65	PJM- MAAC	
New York (NYISO):				
Oswego	Zone C	1,635	UCAP - ROS	
Huntley	Zone A	380	UCAP - ROS	
Dunkirk	Zone A	530	UCAP - ROS	
Astoria Gas Turbines	Zone J	550	UCAP - NYC	
Arthur Kill	Zone J	865	UCAP - NYC	
California (CAISO):				
Encina	SP-15	965	Toll	Expires 12/31/2011
Cabrillo II	SP-15	190	RA Capacity[6]	
El Segundo	SP-15	670	RA Capacity	RA on portion of the plant
Long Beach	SP-15	260	Toll[7]	Expires 8/1/2017
Blythe	SP-15	20	PPA[8]	Expires 12/31/2029
Thermal:				
Dover	PJM - East	104	DPL- South	
Paxton Creek	PJM - West	12	PJM- MAAC	

1. LFRM payments are net of any FCM payments received.
2. Per the terms of the ISO-NE RMR agreement, any FCM transition capacity payments are offset against approved RMR payment. RMR agreements expired June 1, 2010, the first day of the First Installed Capacity Commitment Period of the Forward Capacity Market
3. South Central includes Rockford I and II, which is in PJM and receives capacity payments at the RPM wholesale market clearing price for the RPM RTO region.
4. Somerset has entered into an agreement with the MADEP, to retire or repower the remaining coal-fired unit at Somerset by the end of 2009 which was then extended until September 30, 2010. Subsequently, NRG requested of ISO-NE that it be allowed to place the 109 MW Unit 6 on deactivated reserve effective January 2, 2010, in advance of the required shut-down date. On December 21, 2009, ISO-NE granted NRG's request and NRG is no longer earning capacity revenues from this deactivated unit. On June 1, 2010, NRG decommissioned Somerset unit 2, a 16 MW unit.
5. Indian River Unit 1 will be retired by May 1, 2011 and Indian River Unit 2 was retired on May 1, 2010, which is reflected in the 660 MW capacity value. On February 3, 2010, NRG and DNREC announced a proposed plan to retire the 155MW Unit 3 by December 31, 2013.
6. RA contracts cover the entire Cabrillo II portfolio through 2010 (RA contracts for 88 MW run through November 30, 2013)
7. NRG has purchased back energy and ancillary service value of the toll through July 31, 2011.
8. Blythe reached commercial operation on December 18, 2009 and sells all its capacity under a 20-year full-requirements PPA.

Forecast Non-Cash Contract Amortization Schedules: 2009-2012

Increase / (Decreases) Revenue

($M)	2009					2010				
Revenues	Q1A	Q2A	Q3A	Q4A	Year	Q1A	Q2A	Q3A	Q4E	Year
Power contracts / gas swaps[1]	47	(43)	(51)	(76)	(123)	8	7	32	(2)	45
Fuel Expense	Q1A	Q2A	Q3A	Q4A	Year	Q1A	Q2A	Q3A	Q4E	Year
Fuel and energy supply out-of-market contracts[2]	5	19	26	24	74	13	11	12	9	45
Fuel and energy supply in-the-market contracts[3]	5	8	15	4	32	1	1	3	1	6
Emission allowances (NOx and SO2)	10	10	10	8	38	12	15	12	15	54
Total Net Expenses	10	(1)	(1)	(12)	(4)	0	5	3	7	15

Reduce Cost

Increase Cost

Increase Cost

Increase / (Decreases) Revenue

($M)	2011					2012				
Revenues	Q1E	Q2E	Q3E	Q4E	Year	Q1E	Q2E	Q3E	Q4E	Year
Power contracts / gas swaps[1]	(22)	(17)	3	(27)	(63)	(28)	(22)	(8)	(25)	(83)
Fuel Expense	Q1E	Q2E	Q3E	Q4E	Year	Q1E	Q2E	Q3E	Q4E	Year
Fuel and energy supply out-of-market contracts[2]	5	3	1	2	11	1	1	1	2	5
Fuel and energy supply in-the-market contracts[3]	1	1	3	1	6	2	1	3	1	7
Emission allowances (NOx and SO2)	15	15	15	15	60	13	13	13	13	52
Total Net Expenses	11	13	17	14	55	14	13	15	12	54

Reduce Cost

Increase Cost

Increase Cost

[1] Amortization of power contracts occurs in the revenue line.

[2] Amortization of fuel and energy supply contracts occurs in the fuel and energy supply cost line; includes coal.

[3] Amortization of fuel and energy supply contracts occurs in the fuel and energy supply cost line; includes coal, nuclear, and gas.

Note: Detailed discussion of the above referenced in-the-money and out-of-the money contracts can be found in the NRG 2009 10K

Appendix:
Reg. G Schedules

Reg G.: YTD 2010 Free Cash Flow

$ in millions	Sep 30, 2010	Sep 30, 2009	Variance
Adjusted EBITDA, excl. MtM	**$ 2,071**	**$ 2,129**	**$ (58)**
Interest payments	(555)	(499)	(56)
Income tax	(15)	(41)	26
Collateral	(116)	13	(129)
Working Capital/Other assets & liabilities	(244)	(322)	78
Cash flow from operations	**$ 1,141**	**$ 1,280**	**$ (139)**
Maintenance CapEx	(119)	(160)	41
Environmental CapEx, net	(126)	(138)	12
Preferred Dividends	(7)	(27)	20
Free cash flow - before growth investments	**$ 889**	**$ 955**	**$ (66)**
Growth investments	(78)	(186)	108
NINA capital calls	(173)	(80)	(93)
Free cash flow	**$ 638**	**$ 689**	**$ (51)**

Note: see Appendix slide 34 for a Capital Expenditure reconciliation

Reg G.: 2010 Guidance

$ in millions

	11/4/2010 Guidance	8/2/2010 Guidance
Wholesale	$1,825-1,850	$1,800-1,850
Retail	675-700	650-700
Consolidated adjusted EBITDA	**$2,500-$2,550**	**$2,450-$2,550**
Interest Payments	(648)	(647)
Income Tax	(25)	(75)
Collateral Payments/working capital/other	(297)	(187)
Cash from flow operations	**$1,530-$1,580**	**$1,541-$1,641**
Maintenance CapEx	(228)	(246)
Environmental CapEx, net	(95)	(188)
Preferred Dividends	(9)	(9)
Free cash flow - before growth investments	**$1,198-$1,248**	**$1,098-$1,198**
Growth investments	(321)	(96)
NINA capital calls	(178)	(178)
Free cash flow	**$699-$749**	**$824-$924**

$86 MM increase in collateral during the 3rd quarter

$92 MM Indian River tax exempt funding

Solar - $170 MM

*Repowering*NRG:

El Segundo - $42 MM

Other - $13 MM

Note: original August 2nd FCF guidance of $816-$916 million was adjusted upward by $8 million to reflect actual NRG capital calls from NINA

Reg G.: 2011 Guidance

$ in millions	11/4/2010 Guidance
Wholesale	$1,350-1,450
Retail	480-570
Green Mountain	70-80
Consolidated adjusted EBITDA	**$1,900-$2,100**
Interest Payments	(692)
Income Tax	(50)
Collateral Payments/working capital/other	154
Cash from flow operations	**$1,300-$1,500**
Maintenance CapEx	(246)
Environmental CapEx, net	(111)
Preferred Dividends	(9)
Free cash flow - before growth investments	**$950-$1,150**
Growth investments	(343)
NINA capital calls	(50)
Free cash flow	**$550-$750**

Includes Cottonwood and Dynegy asset acquisitions

Includes $76 MM Indian River tax exempt funding

Solar - $177 MM

Texas Reliability - $30 MM

Electric Vehicle - $13 MM

Other - $14 MM

*Repowering*NRG:

GenConn - $60 MM

El Segundo - $49 MM

Reg. G

Appendix Table A-1: Third quarter 2010 Regional Adjusted EBITDA Reconciliation

The following table summarizes the calculation of adjusted EBITDA and provides a reconciliation to net income

($ in millions)	Reliant Energy	Texas	Northeast	South Central	West	International	Thermal	Corporate	Total
Net Income / (Loss)	$ (20)	$ 439	$ 23	$ 8	$ 20	$ 7	$ 3	$ (257)	$ 223
Plus:									
Net (Gain)/Loss Attributable to Non-Controlling Interest	-	-	-	-	-	-	-	-	-
Income Tax	-	-	-	-	-	3	-	86	89
Interest Expense	1	(19)	14	10	1	2	3	149	161
Amortization of Finance Costs	-	-	-	-	-	-	-	7	7
Amortization of Debt (Discount)/Premium	-	-	-	1	-	-	-	-	1
Depreciation Expense	32	124	29	17	2	-	3	3	210
ARO Accretion Expense	-	-	1	-	1	-	-	-	2
Amortization of Power Contracts	31	(2)	-	(6)	-	-	-	-	23
Amortization of Fuel Contracts	(8)	(1)	-	-	-	-	-	-	(9)
Amortization of Emission Allowances	-	13	-	-	-	-	-	-	13
EBITDA	$ 36	$ 554	$ 67	$ 30	$ 24	$ 12	$ 9	$ (12)	$ 720
Dynegy/Cottonwood Acquisition and Integration Costs	-	-	-	-	-	-	-	3	3
Less: MTM Forward Position Accruals	(147)	127	(17)	(13)	-	-	-	-	(50)
Add: Prior Period MtM Reversals	26	(27)	23	(4)	-	-	-	-	18
Less: Hedge Ineffectiveness	-	12	2	-	-	-	-	-	14
Adjusted EBITDA, excluding MtM	$ 209	$ 388	$ 105	$ 39	$ 24	$ 12	$ 9	$ (9)	$ 777

Reg. G

Appendix Table A-2: Third Quarter 2009 Regional Adjusted EBITDA Reconciliation
The following table summarizes the calculation of adjusted EBITDA and provides a reconciliation to net income

($ in millions)	Reliant Energy	Texas	Northeast	South Central	West	International	Thermal	Corporate	Total
Net Income / (Loss)	$ 393	$ 196	$ 50	$ (34)	$ 16	$ 6	$ 2	$ (351)	$ 278
Plus:									
Net (Gain)/Loss Attributable to Non-Controlling Interest	-	-	-	-	-	-	-	-	-
Income Tax	-	-	-	-	-	1	-	165	166
Interest Expense	15	(12)	15	14	(1)	2	1	130	164
Amortization of Finance Costs	-	-	-	-	-	-	-	10	10
Amortization of Debt (Discount)/Premium	-	-	-	-	-	-	-	4	4
Depreciation Expense	42	119	29	16	2	-	2	2	212
ARO Accretion Expense	-	1	-	-	1	-	-	-	2
Amortization of Power Contracts	85	(17)	-	(8)	-	-	-	-	60
Amortization of Fuel Contracts	(12)	1	-	-	-	-	-	-	(11)
Amortization of Emission Allowances	-	10	-	-	-	-	-	-	10
EBITDA	523	298	94	(12)	18	9	5	(40)	895
Exelon Defense Costs	-	-	-	-	-	-	-	21	21
Integration Costs	-	-	-	-	-	-	-	6	6
Less MTM Forward Position Accruals	(21)	(130)	(66)	(16)	(7)	-	1	-	(239)
Add. Prior Period MtM Reversals	(238)	(7)	7	-	(1)	-	-	-	(239)
Less: Hedge Ineffectiveness	-	17	(1)	-	-	-	-	-	16
Adjusted EBITDA, excluding MtM	$ 306	$ 404	$ 168	$ 4	$ 24	$ 9	$ 4	$ (13)	$ 906

Reg. G

Appendix Table A-3: YTD 2010 Regional Adjusted EBITDA Reconciliation

The following table summarizes the calculation of adjusted EBITDA and provides a reconciliation to net income

($ in millions)	Reliant Energy	Texas	Northeast	South Central	West	International	Thermal	Corporate	Total
Net Income / (Loss)	$ 69	$ 971	$ 73	$ 8	$ 34	$ 36	$ 5	$ (705)	$ 491
Plus:									
Net (Gain)/Loss Attributable to Non-Controlling Interest	-	1	-	-	-	-	-	-	1
Income Tax	-	-	-	-	-	15	-	256	271
Interest Expense	4	(47)	41	30	2	5	5	406	446
Amortization of Finance Costs	-	-	-	-	-	-	-	18	18
Amortization of Debt (Discount)/Premium	-	-	-	4	-	-	-	1	5
Depreciation Expense	91	365	92	49	8	-	8	7	620
ARO Accretion Expense	-	2	(3)	-	2	-	-	-	1
Amortization of Power Contracts	159	(6)	-	(16)	-	-	-	-	137
Amortization of Fuel Contracts	(27)	(4)	-	-	-	-	-	-	(31)
Amortization of Emission Allowances	-	39	-	-	-	-	-	-	39
EBITDA	$ 296	$ 1,321	$ 203	$ 75	$ 46	$ 56	$ 18	$ (17)	$ 1,998
Dynegy/Cottonwood Acquisition and Integration Costs	-	-	-	-	-	-	-	3	3
Less: MTM Forward Position Accruals	(402)	320	(6)	(24)	1	-	-	-	(111)
Add: Prior Period MtM Reversals	(104)	3	72	(14)	-	-	2	-	(41)
Less: Hedge Ineffectiveness	-	-	-	-	-	-	-	-	-
Adjusted EBITDA, excluding MtM	$ 594	$ 1,004	$ 281	$ 85	$ 45	$ 56	$ 20	$ (14)	$ 2,071

Reg. G

Appendix Table A-4: YTD 2009 Regional Adjusted EBITDA Reconciliation

The following table summarizes the calculation of adjusted EBITDA and provides a reconciliation to net income

($ in millions)	**Reliant Energy**	**Texas**	**Northeast**	**South Central**	**West**	**International**	**Thermal**	**Corporate**	**Total**
Net Income / (Loss)	$ 807	$ 510	$ 303	$ (42)	$ 32	$ 143	$ 6	$ (851)	$ 908
Plus:									
Net (Gain)/Loss Attributable to Non-Controlling Interest	-	1	-	-	-	-	-	-	1
Income Tax	-	171	-	-	-	6	-	437	614
Interest Expense	29	16	41	38	-	6	4	306	440
Amortization of Finance Costs	-	-	-	-	-	-	-	24	24
Amortization of Debt (Discount)/Premium	-	-	-	-	-	-	-	11	11
Depreciation Expense	85	353	88	50	6	-	7	5	594
ARO Accretion Expense	-	3	1	-	2	-	-	-	6
Amortization of Power Contracts	160	(49)	-	(19)	-	-	-	-	92
Amortization of Fuel Contracts	(25)	4	-	-	-	-	-	-	(21)
Amortization of Emission Allowances	-	29	-	-	-	-	-	-	29
EBITDA	$ 1,056	$ 1,038	$ 433	$ 27	$ 40	$ 155	$ 17	$ (68)	2,698
Exelon Defense Cost	-	-	-	-	-	-	-	31	31
Integration Cost	-	-	-	-	-	-	-	41	41
FX Loss on MIBRAG Sale Proceeds	-	-	-	-	-	20	-	-	20
Settlement of Pre-Existing Relationship with Reliant Energy	-	-	-	-	-	-	-	(31)	(31)
Gain on Sale of Equity Method Investmer	-	-	-	-	-	(128)	-	-	(128)
Less MTM Forward Position Accruals	72	(43)	70	(30)	(1)	-	2	-	70
Add. Prior Period MtM Reversals	(448)	5	27	-	(1)	-	2	-	(415)
Less: Hedge Ineffectiveness	-	18	(1)	-	-	-	-	-	17
Adjusted EBITDA, excluding MtM	$ 536	$ 1,068	$ 391	$ 57	$ 40	$ 47	$ 17	$ (27)	$ 2,129

Reg. G

Appendix Table A-5: Solar Adjusted EBITDA Reconciliation to Income Before Taxes
The following table summarizes the comparative Income before taxes to adjusted EBITDA

$ in millions

	2010	2011	2012	2013	2014
EBITDA	$ 5	$ 13	$ 26	$ 87	$ 180
Income before taxes	$ 1	$ 3	$ 8	$ 25	$ 20

Reg G: GME non-GAAP Reconciliation

Non-GAAP Reconciliation(1)

Pre-Tax Income	44
Interest Expense	0
Depreciation & Amortization(2)	26
Adjusted EBITDA(3) of Contribution from Assets Acquired	70

(1) The reconciliation is an estimate based upon an initial 12 month period and is not representative of an annual performance metric.

(2) Depreciation & Amortization is a preliminary estimate subject to change upon completion of final acquisition accounting.

(3) Excludes MtM adjustments on economic hedges

Reg. G

- EBITDA and adjusted EBITDA are non GAAP financial measures. These measurements are not recognized in accordance with GAAP and should not be viewed as an alternative to GAAP measures of performance. The presentation of adjusted EBITDA should not be construed as an inference that NRG's future results will be unaffected by unusual or non-recurring items.

- EBITDA represents net income before interest, taxes, depreciation and amortization. EBITDA is presented because NRG considers it an important supplemental measure of its performance and believes debt-holders frequently use EBITDA to analyze operating performance and debt service capacity. EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our operating results as reported under GAAP. Some of these limitations are:
  - EBITDA does not reflect cash expenditures, or future requirements for capital expenditures, or contractual commitments;
  - EBITDA does not reflect changes in, or cash requirements for, working capital needs;
  - EBITDA does not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on debt or cash income tax payments;
  - Although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA does not reflect any cash requirements for such replacements; and
  - Other companies in this industry may calculate EBITDA differently than NRG does, limiting its usefulness as a comparative measure.

- Because of these limitations, EBITDA should not be considered as a measure of discretionary cash available to use to invest in the growth of NRG's business. NRG compensates for these limitations by relying primarily on our GAAP results and using EBITDA and adjusted EBITDA only supplementally. See the statements of cash flow included in the financial statements that are a part of this news release.

- Adjusted EBITDA is presented as a further supplemental measure of operating performance. Adjusted EBITDA represents EBITDA adjusted for gains or losses on the sales of equity method investments; currency loss; Exelon defense costs, and Reliant retail acquisition and integration costs; and factors which we do not consider indicative of future operating performance. The reader is encouraged to evaluate each adjustment and the reasons NRG considers it appropriate for supplemental analysis. As an analytical tool, adjusted EBITDA is subject to all of the limitations applicable to EBITDA. In addition, in evaluating adjusted EBITDA, the reader should be aware that in the future NRG may incur expenses similar to the adjustments in this news release.

- Free cash flow is cash flow from operations less capital expenditures, preferred stock dividends, repowering capital expenditures net of project funding, and NINA Capital Calls and is used by NRG predominantly as a forecasting tool to estimate cash available for debt reduction and other capital allocation alternatives. Free cash flow before growth investments is used to show NRG's ability to fund certain growth initiatives in addition to debt reduction and other capital allocation alternatives. The reader is encouraged to evaluate each of these adjustments and the reasons NRG considers them appropriate for supplemental analysis. Because we have mandatory debt service requirements (and other non-discretionary expenditures) investors should not rely on free cash flow as a measure of cash available for discretionary expenditures.