



NRG's Second Quarter 2011 Results Presentation

August 4, 2011

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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, capital allocation, commercial operations, and renewable energy development strategy. 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, our ability to implement value enhancing improvements to plant operations and companywide processes, our ability to obtain federal loan guarantees, the inability to maintain or create successful partnering relationships, our ability to retain retail customers, our ability to realize value through our commercial operations strategy, and the 2011 Capital Allocation Plan, and share repurchase under the Capital Allocation Plan may be made from time to time subject to market conditions and other factors, including as permitted by United States securities laws.

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Agenda

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

Key Highlights: Second Quarter 2011

★ **Strong Financial Results**

- \$517 million Adjusted EBITDA for the quarter; \$972 million for 1H 2011
- \$200 million Cash Flow from Operations; \$240 million for 1H 2011 (excluding for collateral posted)
- \$3,253 million of total liquidity, \$2,084 million in cash at end of Q2
- \$1,900-2,000 million new 2011 Adjusted EBITDA guidance

★ **Strong Operating Performance**

- Reliant retail achieves net increase in customer count and becomes largest REP in Texas in terms of sales volume
- Green Mountain retail ahead of plan on Adjusted EBITDA and residential customer count, while adding key commercial accounts (Empire State Building and Lord & Taylor)
- Wholesale fleet achieved consistently high availability amid record weather events

★ **Strategic Capital Allocation**

- \$250 million increase in share repurchases, bringing total 2011 share repurchases to \$430 million (\$300 million to go in 2011)
- \$3,900 million first lien debt restructured by extending maturities and simplifying covenant package
- \$2,400 million of 2016 senior notes redeemed, leaving \$1,100 million of 2017 notes to go
- \$562 million of cash used to pay down debt through year to date 2011

★ **Progress with Conventional and Solar Development Projects**

- "Big Three" utility-scale solar projects (Ivanpah, Agua Caliente, CVSR) progress in construction
- Project Amp landmark rooftop solar program wins DOE funding
- Conventional repowering advances with 550 MW El Segundo nearing financial close and 1,040 MW Astoria and 660 MW Old Bridge "in the wings"

Solid and Cash-Generative Core Business

NRG Benefits from these Main Value Drivers of our Core Business...

✓ **Integrated Texas Business Model: Value-generative Retail 'Wrap' with Wholesale Assets in Texas and potential NE growth**

✓ **Robust and Improving Core Market Fundamentals: NRG's assets in prime locations and markets**

✓ **Continuing Reinvestment to Strengthen Core Fleet: Repowering and Greenfield Sites**

...And Maintains and Extends our Unique Advantage in 2011

➤ **Growing retail in both residential and commercial; regional expansion into PJM**
 ➤ **Integrated approach continuing to deliver countercyclical, quantifiable transactional benefits**

➤ **Texas: record demand in 1H**
 ➤ **Stringent EPA regulations to accelerate tighter supply / demand fundamentals in ERCOT**

➤ **GenConn Complete**
 ➤ **El Segundo underway**
 ➤ **Positioning sites for future opportunities: Astoria, Encina, Old Bridge**

Leading to Continued and Strong Free Cash Flow Generation

**FCF before Growth Yield¹:
17-19 %**

¹Cash Flow Yield based on common stock share price of \$23.66 as of August 3, 2011

**FCF before Growth/Share²:
\$4.14-\$4.55 / Share**

²FCF after maintenance and environmental capex but before growth capex per 2011 guidance; calculated by adding back preferred dividends and dividing by the weighted average number of common diluted shares of 244 million for the quarter ended June 30, 2011



Positive market fundamentals expected to drive strong performance from base business



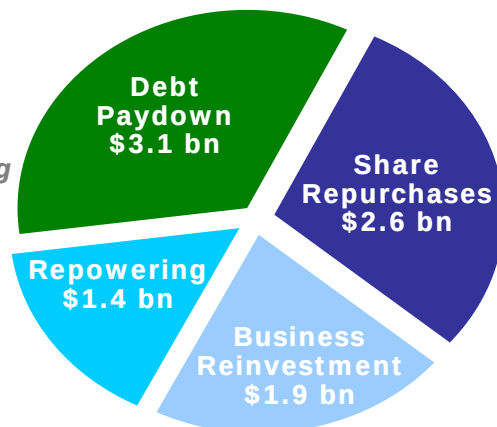
Flexible Capital Allocation

Historical and 2011 Capital Allocation Plan: Balanced and Opportunistic

Historical Capital Allocation (2004-2010)

Plus acquisitions, including

1. Texas Genco (Jan 2006)
2. Reliant (May 2009)
3. Green Mountain (Nov 2010)



2011 Capital Allocation

Estimated excess deployable capital of ~\$1.7 bn¹ is available for:

- ❑ Investment in additional high return growth opportunities
 - Repowering, Solar, Other Green opportunities
- ❑ Additional share repurchases
 - ✓ Increased repurchase program by \$250 MM
- ❑ Potential debt repayments
- ❑ Opportunistic asset/business acquisitions

¹Assuming targeted cash balance of \$700 MM for working capital, margin calls, and construction expenditures

Capital Allocation Drivers and Strategy: 2012 and Beyond

I. Future Capital Allocation Strategy Driven By:

- Simplified Capital Structure and Balance Sheet (with ~\$2.1 bn cash at end of 2011)
- Target Prudent Balance Sheet Management Leverage Metrics
- Flexible and Consistent Adjusted-EBITDA Based Covenants Across the Capital Structure
- Repowering, Solar and Acquisition opportunities
- Business Reinvestment Needs
- Optimal Return of Capital to Shareholders

II. Refinancing Progress Update:

- ❑ Complete refinancing of 2017 notes, projected in Feb 2012



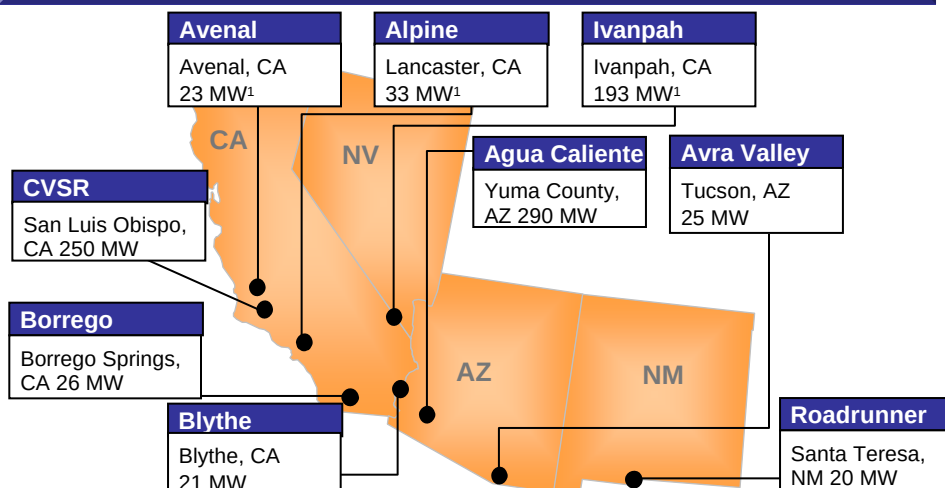
Removal of RP basket restrictions will permit most efficient capital allocation decisions



NRG Solar First Mover Advantage and Strategic Execution



Utility Scale Portfolio



NRG Development Strategy and Risk Mitigation

- Long term PPAs with creditworthy off-takers
- Firm-price EPC & O&M contracts with warranties and performance guarantees
- Non-recourse project financing

Major State Distributed Energy Goals and Mandates

State	California	Arizona	Colorado	New York	New Jersey
DG / DS mandate	"Million Solar Roofs" by 2017; California Solar Initiative; others	4.5% of energy sales from DG (including solar) by 2020	3% for energy sales from DG by 2020 (50% retail/50% wholesale)	0.4788% DG (non-PV is also eligible) by 2015	None ²
RPS Mandate (MW equivalent or GWh)	CA governor Jerry Brown: 12 GW distributed generation (including solar) by 2020	~2,000 MW	~700 MW	~600 MW	5,316 GWh from solar by 2025 (~3,000 MW)

Source: Database of State Incentives for Renewable Energy, June 2011

¹Avenal, Alpine, and Ivanpah net MW NRG ownership shown

²NJ solar renewable energy credits (SRECs) produced by distributed solar generation can be sold to utility buyers to meet RPS compliance requirements

2011-12 Objectives for Utility and Distributed Solar

- ~880 MW with signed PPAs contributing over \$350 million in Adjusted EBITDA when fully operational
- ~20 MW in operation, ~520 MW under construction, with balance to be under construction in latter part of 2011 and all operational by 2014
- Additional ~2 GW in advanced development (including 733 MW Prologis distributed solar rooftop opportunity) with expected COD in 2012+

★ NRG solar investments yield strong levered returns and equity payback in 2-5 years ★



Operations and Commercial Review

Operations Highlights – Second Quarter 2011

☒ **Maintained top safety performance**

- Top decile performance. OSHA recordable rate of 0.78

☒ **Strong plant performance**

- Baseload equivalent availability factor (EAF) of 90.8% for the quarter
- Gas/Oil fleet starting reliability of 98.9% for the quarter

☒ **EPA released final Cross State Air Pollution Rule (CSAPR)**

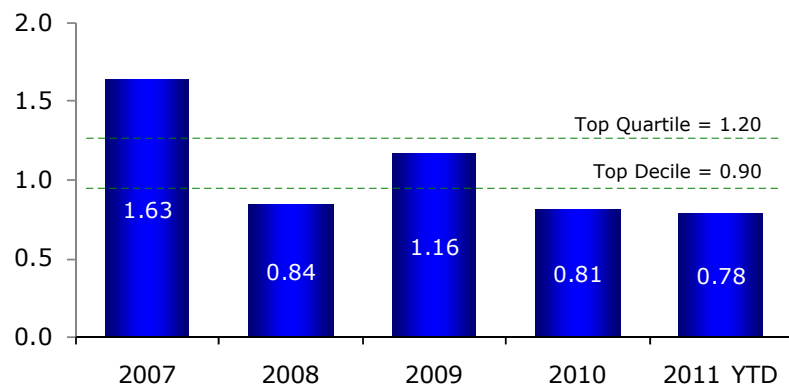
- Reaffirming environmental capital expenditure plan of ~\$720 million

☒ **DEPC projects are on track**

- ☒ Middletown – achieved commercial operation in June 2011
- ☒ Road Runner – startup commenced in July 2011; COD December 2011
- ☐ Indian River – environmental retrofits on schedule, COD January 2012
- ☐ El Segundo – commenced construction, COD August 2013
- ☐ Ivanpah – construction on track, COD 2013

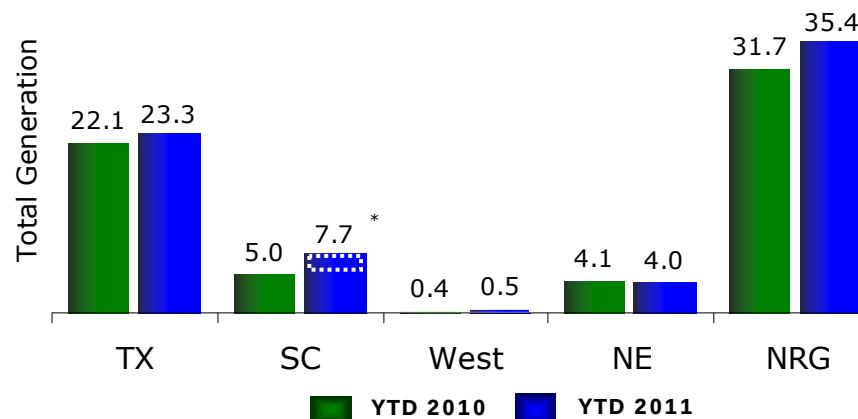
Q2 2011 Operations Update

Safety – Top Decile Performance¹



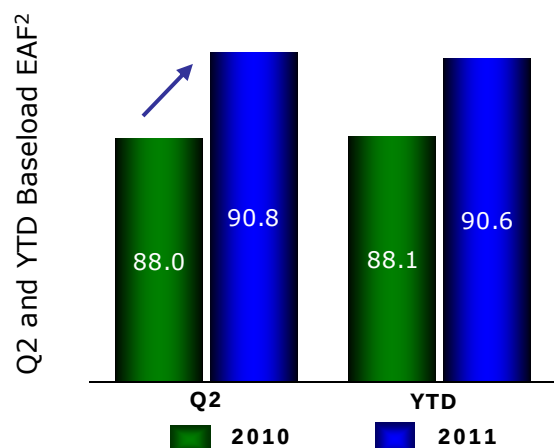
¹ OSHA Top Decile and Top Quartile Rates are Edison Electric Institute Industry Survey

Net Fleet Production (TWh)



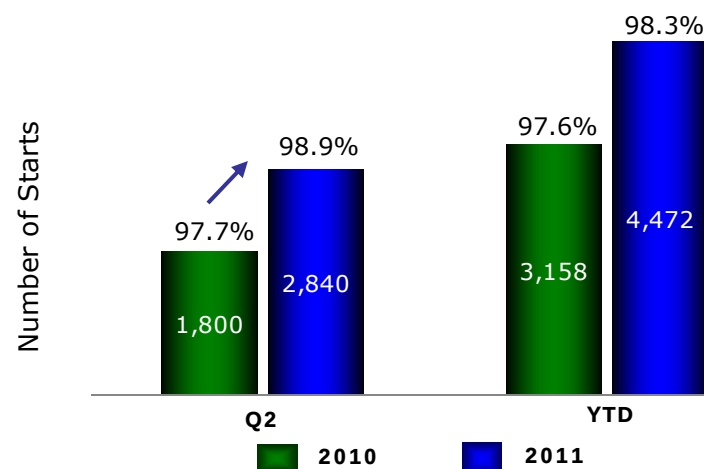
* Includes 2.1 TWh from Cottonwood

Baseload Availability (EAF)



² Equivalent Availability Factor (EAF) – Measures % of maximum equivalent generation available.

Gas / Oil Starting Reliability



Strong performance across all operating metrics

Q2 2011 Retail Operations

Retail Key Drivers

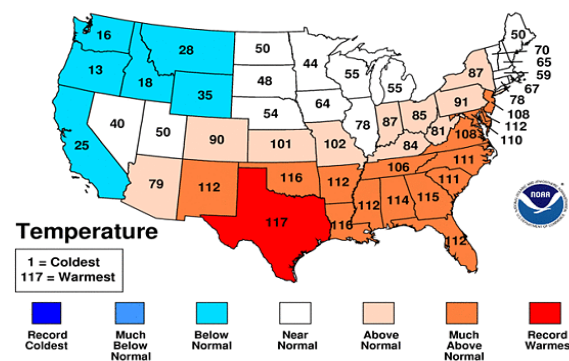
Outperformed Adjusted EBITDA outlook due to:

- Record weather in Texas and effective hedging strategy
- Successful marketing and sales strategies increased customer count
- Continued improvements in economy and collection practices reduced residential (mass) bad debt

Record Weather in Texas

June 2011 Statewide Ranks

National Climatic Data Center/NESDIS/NOAA

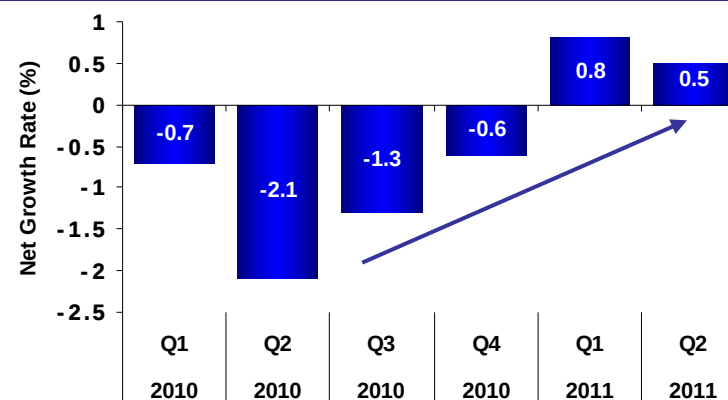


Source: NOAA

Customer Count and Volumes

	Q2 2011	Q1 2011	Q2 2010
Electric Sales Volume (GWh)			
Mass	6,182	4,635	5,821
C&I	6,591	5,691	6,654
Total	12,773	10,326	12,475
Period End Customer Counts (000s of meters)			
Mass	1,477	1,470	1,488
C&I	61	60	63
Total	1,538	1,530	1,551

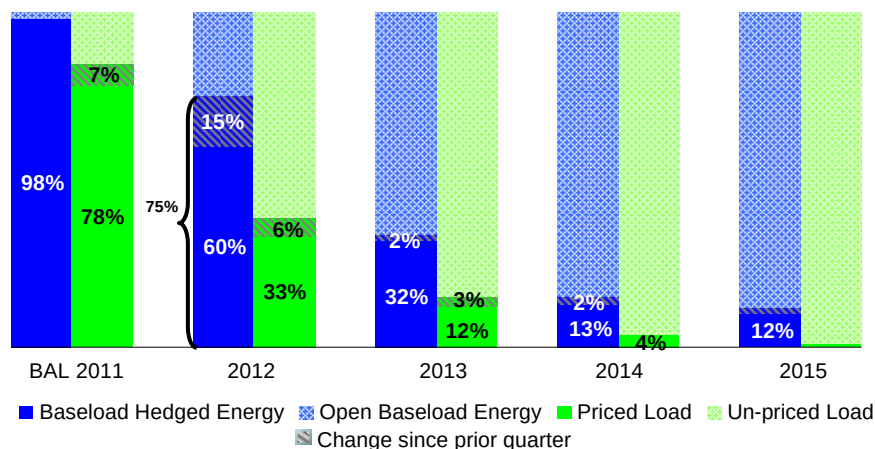
Mass Customer Growth



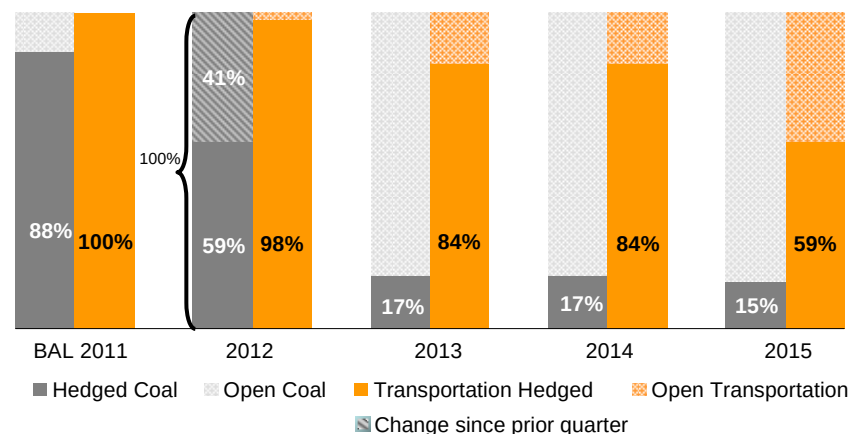
Outperformed Adjusted EBITDA and grew customer count while delivering the strongest customer satisfaction levels

Managing Commodity Price Risk

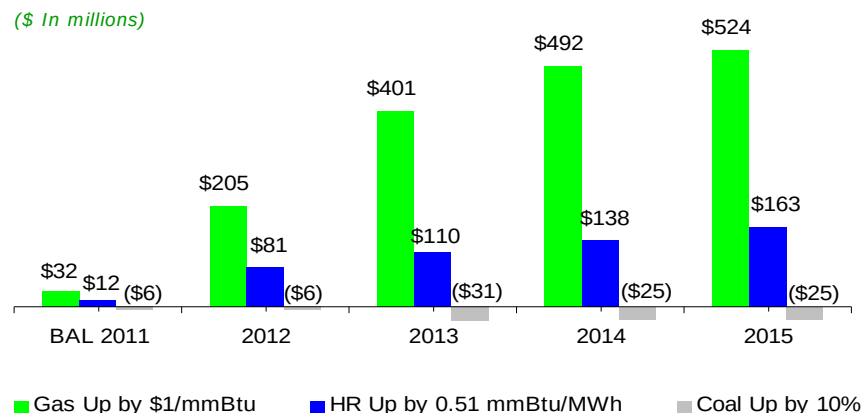
Baseload Generation and Retail Hedge Position⁽¹⁾⁽²⁾



Coal and Transport Hedge Position⁽¹⁾⁽⁵⁾



Baseload Gas Price, Coal and Heat Rate Sensitivity⁽¹⁾⁽³⁾⁽⁴⁾



Commercial Strategy

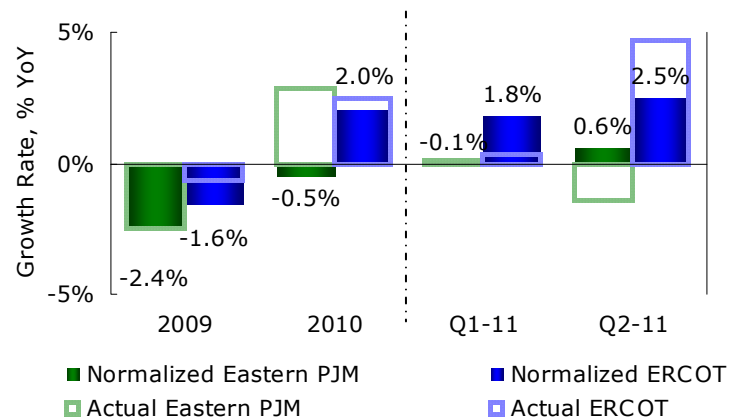
- ✓ Disciplined hedging added 15% to Baseload power portfolio and 41% to coal hedges for 2012
- ✓ Continue to support expansion of retail business into the Northeast
- ✓ Originated multi-year load following opportunities in Texas

(1) Portfolio as of 07/15/2011; (2) Retail load includes Reliant and Green Mountain for Texas, PJM, and NYISO regions. Retail Priced Loads are 100% hedged; (3) Price sensitivity reflects gross margin change from \$1/mmBtu gas price, 0.51 mmBtu/MWh heat rate move, and 10% increase in coal price; (4) 0.51 mmBtu/MWh move in heat rate is 'equally probable' to \$1/mmBtu gas price change; (5) Coal position excludes coal inventory that can be used to cover remaining coal requirement in 2011.

Opportunistic baseload hedging activity in 2012

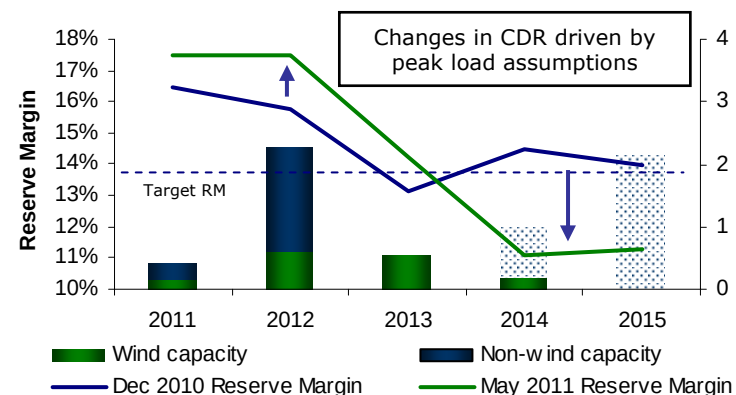
Market Update

Robust ERCOT load growth continues



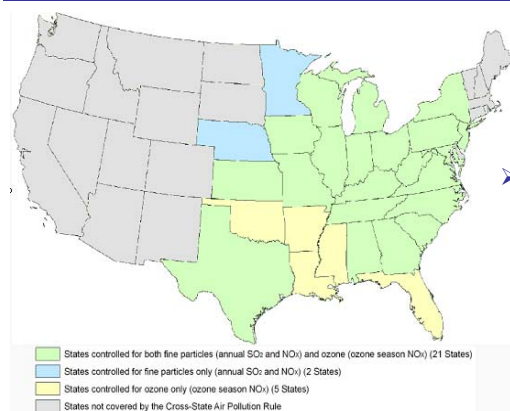
Source: NRG estimates

ERCOT reserve margin



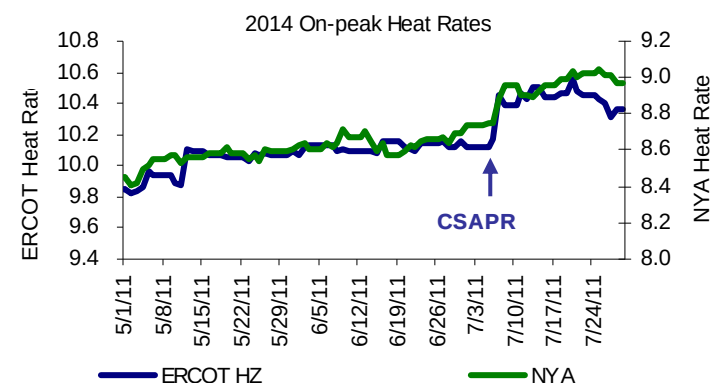
Source: ERCOT Capacity Demand and Reserves Report (CDR), NRG estimates

CSAPR more restrictive than expected



➤ Accelerates retirement decision in the Northeast and possible plant retirements in Texas

...impacting forward heat rates



Source: NRG estimates

Strong fundamentals in ERCOT and market impact of environmental rules benefit NRG portfolio

EPA Cross-State Air Pollution Rule (CSAPR) Update

Environmental Plan

Plant	Coal Type	SO2 / Acid Gas	NOx	Mercury	Status
Huntley & Dunkirk	PRB	DSI ☒	SNCR ☒	ACI/FF ☒	Full controls
Indian River 4	Bit	Dry Scrub ☒	SCR ☒	ACI/ESP/FF ☒	Full controls
Big Cajun II	PRB	Co-benefit FF ☒	LNB/OFA ☒	ACI/FF ☒	Awaiting rule
Limestone	Blend PRB/Lig	Wet Scrub ☒	SNCR ☒	ACI/Scrub ☒	Full controls
Parish 5-7	PRB	Co-benefit FF ☒	SCR ☒	ACI/FF ☒	Awaiting rule
Parish 8	PRB	Wet Scrub ☒	SCR ☒	ACI/FF ☒	
ACI- Activated Carbon Injection DSI- Dry Sorbent Injection with trona ESP- Electrostatic Precipitator FF- Fabric Filter LNB- Low NOx Burner OFA- Over Fire Air SCR- Selective Catalytic Reduction SNCR- Selective Non-Catalytic Reduction Coal Types: Bit- Bituminous Lig- Lignite PRB- Powder River Basin					
☒ Installed ✓Current CapEx					

- **~85 % of NRG's coal consumption is low sulfur, low chloride PRB coal**
- **Limestone plant already blends PRB and is fully scrubbed**

CSAPR – Additional Clarity

- SO₂ and NO_x Cap and Trade
- State caps and allocations - Lower than expected
- Texas: Added back for all programs
- Delaware and Connecticut: No longer included
- Louisiana: NO_x Ozone season only

Integrated Compliance Strategy

- Increase existing scrubber efficiency
- Implement operational changes, fuel switching and seasonal dispatch
- Evaluate low cost controls at Big Cajun versus allowances
- Submit comments to EPA on NRG unit assumptions
- Purchase allowances

CSAPR market impact offsets potential compliance costs



Financial Review

Financial Summary

✓ **Solid Second Quarter and Year-to-Date Results**

- ✓ \$517 million of adjusted EBITDA for the second quarter
 - Reliant Energy: \$176 million of adjusted EBITDA
 - Wholesale: \$341 million of adjusted EBITDA

- ✓ \$972 million of adjusted EBITDA year to date
 - Reliant Energy: \$327 million of adjusted EBITDA
 - Customer retention focus has led to a 17,000 improvement of customer count versus 2010 year-end
 - Wholesale: \$645 million of adjusted EBITDA

- ✓ Second quarter net income of \$621 million
 - Driven by the reversal of tax liabilities following the resolution of the federal tax audit

Raising 2011 Guidance

(\$ in millions)	8 / 4 / 2011 Guidance	5 / 5 / 2011 Guidance
Wholesale	\$1,220-\$1,260	\$1,200-\$1,300
Reliant Energy	\$610-\$660	\$480-\$570
Green Mountain	\$70-\$80	\$70-\$80
Consolidated Adjusted EBITDA	\$1,900-\$2,000	\$1,750-\$1,950
Free Cash Flow – before Growth ¹	\$1,000-\$1,100	\$1,000-\$1,200
Free Cash Flow	\$425-\$525	\$450-\$650

¹FCF after maintenance and environmental capex but before growth capex

Increasing adjusted EBITDA range based on favorable weather and improved customer retention at Reliant

Solid Liquidity

	Jun 30,	Dec 31,
<i>\$ in millions</i>	2011	2010
Cash and Cash Equivalents	\$ 1,939	\$ 2,951
Restricted Cash	145	8
Total Cash	2,084	2,959
Funds Deposited by Counterparties	260	408
Total Cash and Funds Deposited	\$ 2,344	\$ 3,367
Term LC Availability	316	440
Revolver Availability	853	853
Total Liquidity	\$ 3,513	\$ 4,660
Less: Collateral Funds Deposited	(260)	(408)
Total Current Liquidity	\$ 3,253	\$ 4,252

Dec. 31, 2010 Cash	\$ 2,959
Cash flow from operations ¹	1,325
Maintenance and Environmental CapEx, net of financing	(266)
Growth investments, net	(238)
Solar investments, net	(330)
2010 Solar CapEx ²	(267)
Share Repurchases YTD June	(130)
Share Repurchases remainder of Year	(300)
Net debt payments	(625)
Net payments on acquired derivatives	(46)
Other	(28)
Projected year-end 2011 Cash	\$ 2,054

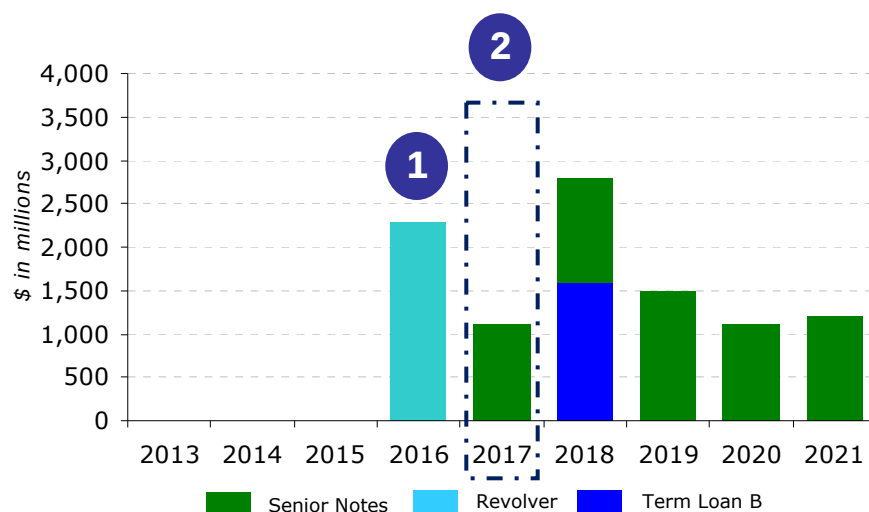
1) 2011 Cash Flow from operations represents the midpoint of 2011 full year guidance of \$1,275M-\$1,375M

2) 2010 Solar CapEx reflects CapEx originally forecasted for 2010 but due to the change in law for eligibility of cash grants the decision was made to push expenditures into 2011

Projected year end cash balance of ~\$2.1 billion after solar and other growth investments of over \$830 million, total share repurchases of \$430 million and net debt paydown of over \$600 million¹⁷

Simplifying the Capital Structure - Update

Scheduled Debt Maturities at June 30, 2011



Refinancing Transaction Update

- 1 Completed in Second Quarter:
 - ✓ Restructured \$3.9 billion multi-tranche first lien facilities
 - ✓ \$2.3 billion revolver replaced
 - ✓ Amended the \$1.6 billion Term Loan B facility
 - ✓ 2016 Senior notes refinanced
- 2 Expect to Complete:
 - \$1.1 billion 2017 senior notes

Benefit to NRG stakeholders

- Extends debt maturity profile
- Aligns our covenant package throughout the NRG capital structure
 - Enhances Capital Allocation flexibility
 - Eliminates excess cash flow sweep
 - Eliminates investment basket restrictions
- Significant LC flexibility through utilizing Revolver versus Term LC

As market conditions permit, NRG will refinance the 2017 Senior Notes completing the Capital Structure simplification



Summary and Q&A

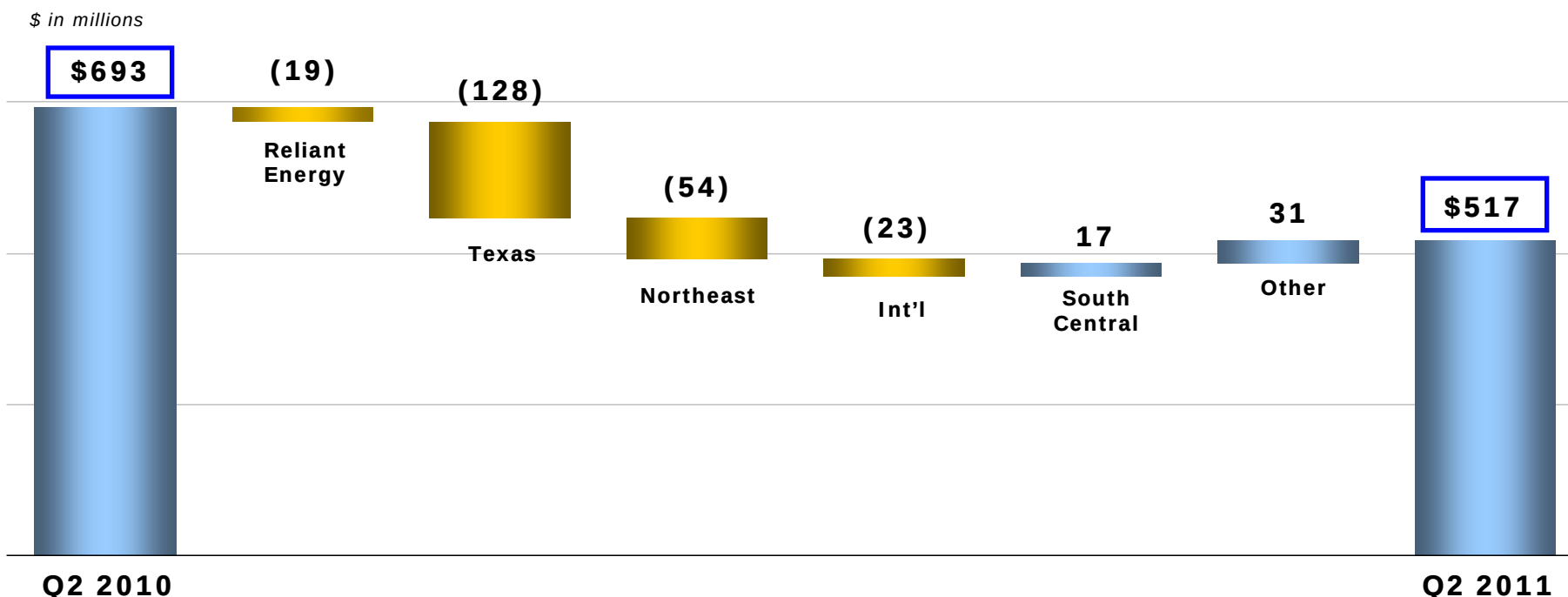
The NRG Value Proposition

NRG Value Components	NRG Value Drivers
I. Solid and Cash-Generative Core Business	✓ Top-performing, complementary core businesses, both in generation and in retail ✓ Market fundamentals in core markets remain strong, and gas fundamentals improving ✓ Unique retail franchises drive growth while reducing cyclicity and enterprise risk
II. Value-Enhancing and High-Growth Green Investments	✓ ~880 MW utility-scale solar pipeline and 733 MW distributed-scale solar program are largest in US ✓ Consumer-driven, emerging green/clean energy businesses (Green Mountain Energy, eVgo) ✓ Substantial high-efficiency gas-fired repowering projects near high-value load centers
III. Flexible Capital Allocation	✓ Relentlessly high FCF yield operations ✓ Simplified capital structure facilitates more optimal capital allocation ✓ Sizeable return of capital to shareholders while adhering to prudent balance sheet management



Appendix

Q2 Adjusted EBITDA – 2011 vs. 2010



Q2 2010

Reliant Energy

- Gross margin declined due to lower revenue pricing on customer acquisitions and renewals and 2% fewer Mass customers. Partially offsetting the decline was a 9% increase in Mass customer usage, driven by favorable weather, and lower supply costs
- Increased marketing costs related to advertising campaigns and sponsorship agreements

Texas

- Lower energy margins resulting from a 14% decline in average realized prices, driven by lower hedged prices, and higher fuel surcharges
- Higher generation of 8% partially offset the decline in energy margins due to a 3% improvement in capacity factors, warmer weather, and the addition of South Trent (acquired June 14, 2010)

Other

- Corp. \$26M (addition of Green Mountain), West \$3M and Thermal \$2M

Northeast

- Lower realized margins due to a 38% decline in realized prices
- Decrease in capacity revenues mainly due to lower realized LFRM prices and volumes and lower prices in New York
- Lower operating expenses due to headcount reductions, less outage work in 2011, and 2010 inventory write offs at Arthur Kill

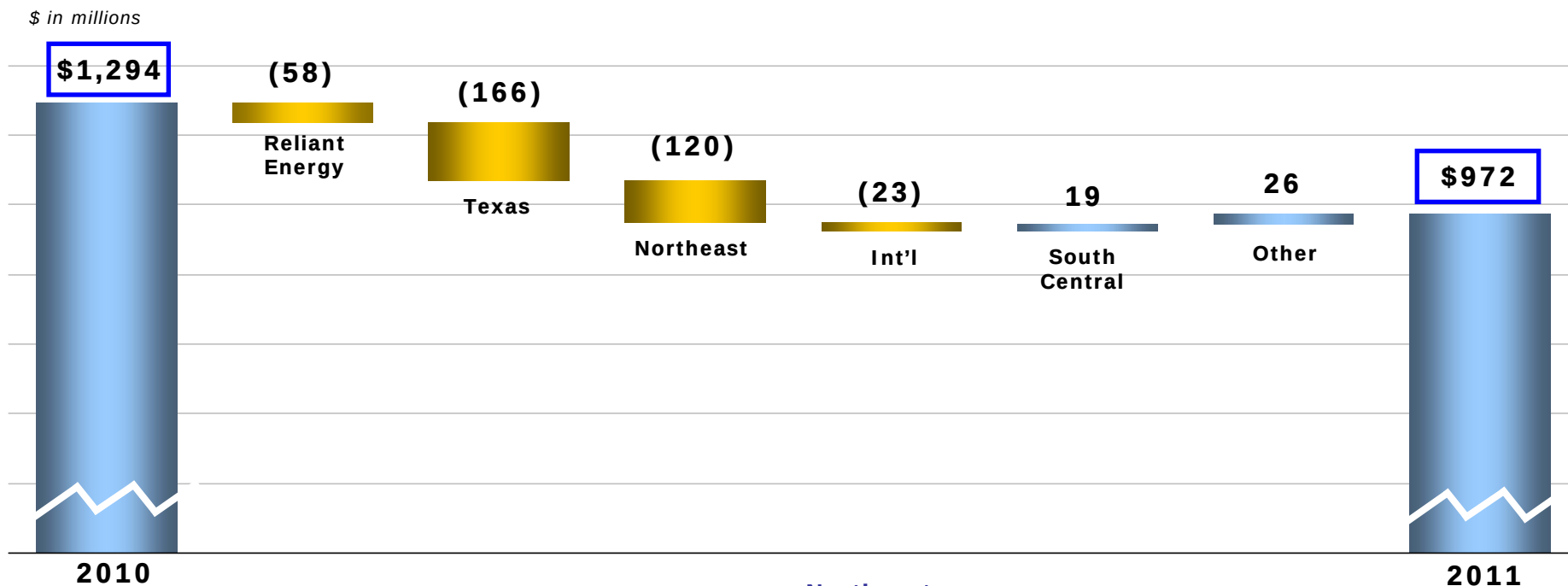
South Central

- Gross margin increased as the acquisition of Cottonwood enabled increased merchant activity and the addition of two new contracts led to higher contract revenue
- Favorable operating expenses due to less outage work in 2011 offset by spending on Cottonwood which was not owned in the prior year

International

- 2010 included a favorable contract settlement and foreign currency gains which did not recur in 2011

Year-to-Date Adjusted EBITDA – 2011 vs. 2010



Reliant Energy

- Gross margins declined due to lower revenue pricing on customer acquisitions and renewals and 3% fewer Mass customers. Partially offsetting the decline was a 4% increase in Mass customer usage, driven by favorable weather, and lower supply costs
- Increased marketing costs related to advertising campaigns and sponsorship agreements
- Bad debt favorable due to improved customer payment patterns

Texas

- Lower energy margins driven by a 12% decline in average realized energy versus the prior year period and an increase in fuel costs due to higher fuel surcharges
- Increased generation partially offset the lower energy margins, driven by an improvement in availability, warmer weather and the addition of South Trent which contributed 187k MWh

Northeast

- Lower energy margins due to a decrease of 27% on realized prices in 2011 compared to 2010 in addition to a 4% decline in generation
- Decrease in capacity revenue due to lower LFRM realized prices and volumes and lower prices in New York
- Favorable operating expenses due to headcount reductions to align with market conditions, less outage work in 2011 compared to 2010, and expenses in 2010 related to the planned closure of Indian River Unit 3

South Central

- Gross margin increased as the acquisition of Cottonwood enabled increased merchant sales activity and the addition of three new contracts led to higher contract revenue
- Lower operating expenses due to less work in 2011 offset by spending on Cottonwood which was not owned in the prior year

Other

- Corporate - Green Mountain acquisition on November 5, 2010

Capital Expenditures and Growth Investments – 2011 YTD Results



<i>\$ in millions</i>	Maintenance		Environmental		Growth investments, net		Solar investments, net		Total
Capital Expenditures, excluding NINA:									
Northeast	\$	4	\$	91	\$	-	\$	-	\$ 95
Texas		60		-		7		-	67
South Central		12		-		-		-	12
West		11		-		133		547	691
Reliant Energy		7		-		-		-	7
Other		13		-		5		-	18
Accrued CapEx	\$	107	\$	91	\$	145	\$	547	\$ 890
Accrual impact		5		5		(2)		(80)	(72)
Total Cash CapEx	\$	112	\$	96	\$	143	\$	467	\$ 818
GenConn Equity Investment, net		-		-		63		-	63
Energy Technology Ventures and other growth		-		-		17		-	17
Solar investments and fees ¹		-		-		-		176	176
Project Funding, net of fees:									
Solar		-		-		-		(466)	(466)
Indian River bonds		-		(95)		-		-	(95)
Total Capital Expenditures and Growth investments, net	\$	112	\$	1	\$	223	\$	177	\$ 513

¹ Solar Investments and fees includes the initial investment in the Ivanpah project; \$98 million of project reserves connected to the Ivanpah project that are placed in restricted cash on the balance sheet; and other project costs

Capital Expenditures and Growth Investments – 2011 Guidance



<i>\$ in millions</i>	Maintenance		Environmental		Growth investments, net		Solar investments, net		Total
Capital Expenditures, excluding NINA:									
Northeast	\$	22	\$	163	\$	-	\$	-	\$ 185
Texas		100		-		28		-	128
South Central		23		7		-		-	30
West		17		-		306		1,885	2,208
Reliant Energy		19		-		-		-	19
Electric Vehicles		-		-		11		-	11
IDC/Other		36		16		18		-	70
Accrued CapEx	\$	217	\$	186	\$	363	\$	1,885	\$ 2,651
Accrual impact		-		-		-		-	-
Total Cash CapEx	\$	217	\$	186	\$	363	\$	1,885	\$ 2,651
GenConn Equity Investment, net		-		-		70		-	70
Energy Technology Ventures and other growth		-		-		31		-	31
Solar investments and fees ¹		-		-		-		194	194
2010 Solar CapEx		-		-		-		(267)	(267)
Project Funding, net of fees:									
El Segundo Repowering		-		-		(226)		-	(226)
Solar		-		-		-		(1,482)	(1,482)
Indian River bonds		-		(137)		-		-	(137)
Total Capital Expenditures and Growth investments, net	\$	217	\$	49	\$	238	\$	330	\$ 834

¹ Solar Investments and fees includes the initial investment in the Ivanpah project; additional initial investments in other projects forecasted for the remainder of the year; \$37 million of project reserves connected to the Ivanpah project that are placed in restricted cash on the balance sheet; and other project costs

Q2 2011 Generation & Operational Performance Metrics



(MWh in thousands)	2011	2010	Change	%	2011		2010	
					EAF ¹	NCF ²	EAF ¹	NCF ²
Texas	12,906	11,963	943	8	87%	53%	91%	47%
Northeast	2,344	1,980	364	18	84	11	88	10
South Central	3,628	3,221	407	13	86	40	82	37
West	49	28	21	75	77	5	88	4
Total	18,927	17,192	1,735	10	85 %	34 %	89 %	31 %
Texas Nuclear	2,052	2,094	(42)	(2)	80%	80%	83%	82%
Texas Coal	8,044	7,723	321	4	95	89	95	85
NE Coal	1,469	1,299	170	13	84	38	85	31
SC Coal	2,538	2,346	192	8	94	77	76	73
Baseload	14,103	13,462	641	5	91 %	76 %	88 %	72 %
Solar	16	15	1	7	n/a	n/a	n/a	n/a
Wind	362	237	125	53	n/a	44	n/a	42
Intermittent	378	252	126	50	n/a	44 %	n/a	42 %
Oil	14	12	2	17	78%	1%	95%	1%
Gas - Texas	1,875	1,390	485	35	82	16	90	11
Gas - NE	396	377	19	5	84	4	86	4
Gas - SC ³	1,124	20	1,104	5,520	81	19	89	1
Gas - West	33	13	20	154	77	5	88	4
Intermediate / Peaking	3,442	1,812	1,630	90	82 %	11 %	89 %	6 %
Purchased Power	1,004	1,666	(662)	(40)				
Total	18,927	17,192	1,735	10				

¹ Equivalent Availability Factor

² Net Capacity Factor

³ SC Gas Generation increase driven by the acquisition of Cottonwood

YTD 2011 Generation & Operational Performance Metrics



(MWh in thousands)	2011	2010	Change	%	2011		2010	
					EAF ¹	NCF ²	EAF ¹	NCF ²
Texas	24,263	22,842	1,421	6	87%	48%	90%	45%
Northeast	4,936	4,734	202	4	87	12	90	12
South Central	7,474	6,399	1,075	17	90	42	86	40
West	83	97	(14)	(14)	81	5	82	4
Total	36,756	34,072	2,684	8	87 %	33 %	89 %	31 %
Texas Nuclear	4,631	4,468	163	4	90%	91%	87%	88%
Texas Coal	15,133	14,735	398	3	91	84	90	82
NE Coal	3,216	3,622	(406)	(11)	88	42	90	44
SC Coal	5,428	4,964	464	9	94	84	80	77
Baseload	28,408	27,789	619	2	91 %	77 %	88 %	74 %
Solar	28	27	1	4	n/a	n/a	n/a	n/a
Wind	635	438	197	45	n/a	51	n/a	40
Intermittent	663	465	198	43	n / a	51 %	n / a	40 %
Oil	41	26	15	58	89%	1%	95%	1%
Gas - Texas	2,594	2,229	365	16	83	12	90	9
Gas - NE	654	429	225	52	85	4	89	2
Gas - SC ³	2,231	44	2,187	4,970	88	19	92	1
Gas - West	55	70	(15)	(21)	81	5	82	4
Intermediate / Peaking	5,575	2,798	2,777	99	85 %	9 %	89 %	5 %
Purchased Power	2,110	3,020	(910)	(30)				
Total	36,756	34,072	2,684	8				

¹ Equivalent Availability Factor

² Net Capacity Factor

³ SC Gas Generation increase driven by the acquisition of Cottonwood

Fuel Statistics

	2 nd Quarter		Year to Date	
Domestic	2011	2010	2011	2010
Cost of Gas (\$ / mmBTU)	\$ 4.47	\$ 4.81	\$ 4.46	\$ 4.98
Coal Consumed (mm Tons)	7.7	7.2	15.2	14.6
PRB Blend	83%	84%	84%	84%
Northeast	70%	66%	74%	69%
South Central	100%	100%	100%	100%
Texas	80%	81%	80%	81%
Coal Costs (\$ / mmBTU)	\$ 2.21	\$ 2.02	\$ 2.18	\$ 2.02
Coal Costs (\$ / Tons)	\$ 35.76	\$ 33.00	\$ 35.50	\$ 33.25

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, Resource Adequacy (RA) contracts, power purchase agreement (PPA) contracts, and tolling arrangements. The ERCOT (Texas) region does not have a capacity market. In South Central,³ NRG earns significant capacity revenue from its long-term contracts. As of June 30, 2011, 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 56% of cooperative contract load, while the remaining three expire in 2014 and comprise 44% 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. 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, PPA, and Tolling Arrangements	Tenor
NEPOOL (ISO NE):				
Devon	SWCT	135	LFRM/FCM ¹	RMR ended June 2010
Connecticut Jet Power	SWCT	140	LFRM/FCM ¹	
Montville	CT – ROS	500	FCM ²	
GenConn Devon	SWCT	95	FCM ⁹	
GenConn Middletown	CT-ROS	95	FCM ⁹	
Middletown	CT – ROS	770	FCM ²	RMR ended June 2010
Norwalk Harbor	SWCT	340	FCM ²	RMR ended June 2010
PJM:				
Indian River	PJM - East	580 ⁴	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 ⁵	RA on portion of the plant ⁸
El Segundo	SP-15	670	RA Capacity	
Long Beach	SP-15	260	Toll ⁶	
Blythe	SP-15	20	PPA ⁷	Expires 12/31/2029
Thermal:				
Dover	PJM - East	105	DPL- South	
Paxton Creek	PJM - West	12	PJM- MAAC	

1. LFRM payments are net of any FCM payments received.

2. 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. Indian River Unit 1 was retired on May 1, 2011 and Indian River Unit 2 was retired on May 1, 2010, which is reflected in the 580 MW capacity value. On February 3, 2010, NRG and DNREC announced a proposed plan to retire the 155MW Unit 3 by December 31, 2013.

5. RA contracts cover the entire Cabrillo II portfolio through 2010 and 2011 (RA contracts for 88 MW run through November 30, 2013)

6. NRG has purchased back energy and ancillary service value of the toll through July 31, 2014. Toll expires August 1, 2017

7. Blythe reached commercial operation on December 18, 2009 and sells all its capacity under a 20-year full-requirements PPA

8. El Segundo includes approximately 335 MW and 596 MW of RA contracts for 2010 and 2011, respectively.

9. GenConn's energy and capacity are sold pursuant to a 30 year cost of service type contract with the Connecticut Light and Power Company under which FCM and LFRM revenues are netted against amounts received

Near-term NRG Solar Portfolio with Scale and Diversity

Project	Location	Net ⁽¹⁾ MW _{AC}	PPA Offtaker (Rating)	PPA Term	Technology (Provider)	Debt Financing (expected date of financial close)	Status and Expected COD
Agua Caliente	Yuma County, AZ	290	PG&E (A3 / BBB+)	25 years	PV (First Solar)	Conditional commitment - \$967 MM DOE loan guarantee (1/2011, financial close expected Q3 2011)	Under construction (2012-14)
CVSR	San Luis Obispo, CA	250	PG&E (A3 / BBB+)	25 years	PV (SunPower)	Conditional commitment - \$1.2 BN DOE loan guarantee (4/2011, financial close expected Q3 2011)	Development (2012-13)
Ivanpah	Ivanpah, CA	193	PG&E/ SCE (A3 / BBB+)	20 – 25 years	CSP (BrightSource) ⁽²⁾	Closed - \$1.6 BN DOE loan guarantee (4/2011)	Under construction (2013)
Alpine	Lancaster, CA	33	PG&E (A3 / BBB+)	20 years	PV (TBD) ⁽²⁾	Commercial Bank Debt (Q4/2011)	Development (Q3 2012)
Borrego	Borrego Springs, CA	26	SDG&E (A2 / A)	25 years	PV (TBD)	Commercial Bank Debt (Q1/2012)	Development (Q3 2012)
Avra Valley	Pima County, AZ	25	TEP (Baa3 / BB+)	20 years	PV (TBD)	Commercial Bank Debt (Q1/2012)	Development (Q3 2012)
Avenal	Kings County, CA	23	PG&E (A3 / BBB+)	20 years	PV (Sharp) ⁽²⁾	Closed - \$210 MM project financing (9/2010)	Under construction (Q3/2011)
Blythe	Blythe, CA	21	SCE (A3 / BBB+)	20 years	PV (First Solar)	Closed - \$36 MM project financing (6/2010)	Operating (Q4/2009 ⁽³⁾)
Roadrunner	Santa Teresa, NM	20	El Paso Electric (Baa2 / BBB)	20 years	PV (First Solar)	Closed - \$73 MM project financing (5/2011)	Under construction (8/2011)
TOTAL		881 MW					

Notes:

1. Net after station service and losses
2. Equity partners are BrightSource and one other partner on Ivanpah and a strategic partner on Alpine and Avenal
3. COD on December 2009

Simplifying the Covenant Package

Indentures (2017 Notes)

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

Adders to RP:

- + Issuance of stock
- + Issuance of convertible preferred

Deductions to RP:

- Payments of dividends
- Repurchases of stock
- Payment of dividends on new preferred

Items that do not increase basket

- Asset Sales (Gains or Losses)

RP Growth Parameter

- 50% of Net Income

Indentures (2018, 2019, 2020, and 2021 Notes)

Based on EBITDA and currently drives RP capacity limitations; Governed by increases in EBITDA

Adders to RP:

- + Issuance of stock
- + Issuance of convertible preferred

Deductions to RP:

- Payments of dividends
- Repurchases of stock
- Payment of dividends on new preferred

Items that do not increase basket

- Asset Sales (Gains or Losses)

RP Growth Parameter

- EBITDA less 1.4x interest expense

Credit Agreement

Matches the 2018, 2019, 2020, and 2021 Note Indentures

Adders to RP:

- + Issuance of stock
- + Issuance of convertible preferred

Deductions to RP:

- Payments of dividends
- Repurchases of stock
- Payment of dividends on new preferred

RP Growth Parameter

- EBITDA less 1.4x interest expense

Covenant Package:

- No Investment Basket
- No Capex limitations
- No Excess Cash Flow sweep
- Retain maintenance covenants only – Debt/EBITDA and EBITDA/Interest

¹ Cash flow defined as: cash from operations, less maintenance and environmental CapEx, less net investment in growth CapEx, less principal payments

Forecast Non-Cash Contract Amortization Schedules: 2010-2013

	(\$M)	2010					2011				
		Q1A	Q2A	Q3A	Q4A	Year	Q1A	Q2A	Q3E	Q4E	Year
Increase / (Decreases) Revenue	Revenues										
	Power contracts / gas swaps¹	8	7	32	(4)	43	(33)	(27)	(5)	(35)	(100)
	Fuel Expense										
	Fuel out-of-market contracts²	13	11	12	9	45	6	3	1	3	13
	Fuel in-the-market contracts³	1	1	3	4	9	1	1	3	1	6
	Emission Allowances (Nox and SO2)	12	15	12	12	51	13	14	15	14	56
	Total Net Expenses	0	5	3	7	15	8	12	17	12	49

	(\$M)	2012					2013				
		Q1E	Q2E	Q3E	Q4E	Year	Q1E	Q2E	Q3E	Q4E	Year
Increase / (Decreases) Revenue	Revenues										
	Power contracts / gas swaps¹	(32)	(25)	(11)	(28)	(96)	(16)	(12)	(3)	(1)	(32)
	Fuel Expense										
	Fuel out-of-market contracts²	2	1	1	3	7	1	1	0	0	2
	Fuel in-the-market contracts³	2	1	3	1	7	2	2	3	1	8
	Emissions allowances (Nox and SO2)	8	9	9	9	35	9	9	9	9	36
	Total Net Expenses	8	9	11	7	35	10	10	12	10	42

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 2010 10K

Appendix: Reg. G Schedules

Reg. G: YTD 2011 Free Cash Flow

<i>\$ in millions</i>	Jun 30, 2011	Jun 30, 2010	Variance
Adjusted EBITDA, excl. MtM	\$ 972	\$ 1,294	\$ (322)
Interest payments	(485)	(330)	(155)
Income tax	(25)	(21)	(4)
Collateral	69	(30)	99
NINA capital calls - post deconsolidation	(11)	-	(11)
Working capital/Other assets & liabilities	(211)	(308)	97
Cash flow from operations	\$ 309	\$ 605	\$ (296)
Reclassifying of receipts (payments) of financing element of acquired derivatives	(46)	27	(73)
Adjusted Cash flow from operations	\$ 263	\$ 632	\$ (369)
Maintenance CapEx	(112)	(70)	(42)
Environmental CapEx, net	(1)	(88)	87
Preferred dividends	(5)	(5)	-
Free cash flow - before growth investments	\$ 145	\$ 469	\$ (324)
Growth investments, net	(223)	(11)	(212)
Solar investments, net ¹	(177)	-	(177)
NINA capital calls - pre deconsolidation	(7)	(163)	156
Free cash flow	\$ (262)	\$ 295	\$ (557)

¹ Solar Investments, net includes \$98 million of project reserves connected to the Ivanpah project that are placed in restricted cash on the balance sheet

Note: see Appendix slide 24 for a Capital Expenditure reconciliation

Reg. G: 2011 Guidance

\$ in millions

	8/4/2011 Guidance	5/5/2011 Guidance
Wholesale	\$1,220-\$1,260	\$1,200-\$1,300
Reliant Energy	610-660	480-570
Green Mountain	70-80	70-80
Consolidated adjusted EBITDA	\$1,900-\$2,000	\$1,750-\$1,950
Interest Payments	(774)	(776)
Income Tax	(50)	(50)
Collateral	166	176
NINA capital calls - post-deconsolidation	(19)	-
Working capital/other	53	167
Cash flow from operations	\$1,275-\$1,375	\$1,250-\$1,450
Maintenance CapEx	(217)	(205)
Environmental CapEx, net	(49)	(48)
Preferred Dividends	(9)	(9)
Free cash flow - before growth investments	\$1,000-\$1,100	\$1,000-\$1,200
Growth investments, net	(238)	(181)
Solar investments, net ¹	(330)	(337)
NINA capital calls - pre-deconsolidation	(7)	(26)
Free cash flow	\$425 - \$525	\$450 - \$650

¹ Solar Investments, net includes \$37 million of project reserves connected to the Ivanpah project that are placed in restricted cash on the balance sheet

Note: see Appendix slide 25 for a Capital Expenditure reconciliation

Reg. G

Appendix Table A-1: Second quarter 2011 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)	\$ 31	\$ 203	\$ 19	\$ 12	\$ 12	\$ 6	\$ (2)	\$ 340	\$ 621
Plus:									
Income Tax	-	-	-	-	-	2	-	(632)	(630)
Interest Expense	1	2	11	10	1	1	3	138	167
Loss on Debt Extinguishment	-	-	-	-	-	-	-	115	115
Depreciation and Amortization Expense	24	122	27	22	3	-	4	20	222
ARO Accretion Expense	-	-	1	-	1	-	-	-	2
Amortization of Contracts	37	14	-	(5)	-	-	-	9	55
EBITDA	\$ 93	\$ 341	\$ 58	\$ 39	\$ 17	\$ 9	\$ 5	\$ (10)	\$ 552
Impairments on investments	-	-	-	-	-	-	-	11	11
MTM losses/(gains)	83	(126)	(11)	(2)	(3)	-	-	13	(46)
Adjusted EBITDA, excluding MtM	\$ 176	\$ 215	\$ 47	\$ 37	\$ 14	\$ 9	\$ 5	\$ 14	\$ 517

Reg. G

Appendix Table A-2: Second 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)	277	157	(2)	4	8	21	(2)	(253)	210
Plus:									
Net Loss Attributable to Non-Controlling									
Interest	-	1	-	-	-	-	-	-	1
Income Tax	-	-	-	-	-	10	-	107	117
Interest Expense	2	(15)	14	11	1	1	1	132	147
Depreciation and Amortization Expense	29	124	31	16	3	-	3	2	208
ARO Accretion Expense	-	1	-	-	-	-	-	-	1
Amortization of Contracts	50	10	-	(5)	-	-	-	-	55
EBITDA	358	278	43	26	12	32	2	(12)	739
MTM losses/(gains)	(163)	65	58	(6)	(1)	-	1	-	(46)
Adjusted EBITDA, excluding MtM	195	343	101	20	11	32	3	(12)	693

Reg. G

Appendix Table A-3: YTD 2011 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)	303	210	(13)	26	25	14	3	(207)	361
Plus:									
Income Tax	-	-	-	-	-	4	-	(739)	(735)
Interest Expense	2	(10)	27	21	2	3	5	290	340
Loss on Debt Extinguishment	-	-	-	-	-	-	-	143	143
Depreciation and Amortization Expense	48	244	56	42	6	-	7	24	427
ARO Accretion Expense	-	1	1	-	2	-	-	-	4
Amortization of Contracts	75	28	-	(10)	-	-	1	18	112
EBITDA	428	473	71	79	35	21	16	(471)	652
Impairment on investments	-	-	-	-	-	-	-	492	492
MTM losses/(gains)	(101)	(24)	(14)	(14)	(7)	-	-	(12)	(172)
Adjusted EBITDA, excluding MtM	327	449	57	65	28	21	16	9	972

Reg. G

Appendix Table A-4: 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)	89	532	50	-	14	29	2	(448)	268
Plus:									
Net Loss Attributable to Non-Controlling Interest	-	1	-	-	-	-	-	-	1
Income Tax	-	-	-	-	-	12	-	170	182
Interest Expense	3	(28)	27	23	1	3	2	269	300
Depreciation and Amortization Expense	59	241	63	32	6	-	5	4	410
ARO Accretion Expense	-	2	(4)	-	1	-	-	-	(1)
Amortization of Contracts	109	18	-	(10)	-	-	-	-	117
EBITDA	260	766	136	45	22	44	9	(5)	1,277
MTM losses/(gains)	125	(151)	41	1	(1)	-	2	-	17
Adjusted EBITDA, excluding MtM	385	615	177	46	21	44	11	(5)	1,294

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 (including loss on debt extinguishment), 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 mark-to-market gains or losses, asset write offs and impairments; 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.
- Adjusted cash flow from operating activities is a non-GAAP measure NRG provides to show cash from operations with the reclassification of net payments of derivative contracts acquired in business combinations from financing to operating cash flow. The Company provides the reader with this alternative view of operating cash flow because the cash settlement of these derivative contracts materially impact operating revenues and cost of sales, while GAAP requires NRG to treat them as if there was a financing activity associated with the contracts as of the acquisition dates.
- Free cash flow is cash flow from operations less capital expenditures, preferred stock dividends and repowering capital expenditures net of project funding and is used by NRG predominantly as a forecasting tool to estimate cash available for 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 adjusted cash flow from operating activities or free cash flow as a measure of cash available for discretionary expenditures.