NRG Energy Inc.

Fourth Quarter and Full Year 2018 Earnings Presentation

February 28, 2019

Safe Harbor

Forward-Looking Statements

In addition to historical information, the information presented in this presentation includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act. These statements involve estimates, expectations, projections, goals, assumptions, known and unknown risks and uncertainties and can typically be identified by terminology such as "may," "should," "could," "objective," "projection," "forecast," "goal," "guidance," "outlook," "expect," "intend," "seek," "plan," "think," "anticipate," "estimate," "predict," "target," "potential" or "continue" or the negative of these terms or other comparable terminology. Such forward-looking statements include, but are not limited to, statements about the Company's future revenues, income, indebtedness, capital structure, plans, expectations, objectives, projected financial performance and/or business results and other future events, and views of economic and market conditions.

Although NRG believes that its expectations are reasonable, it can give no assurance that these expectations will prove to be correct, and actual results may vary materially. Factors that could cause actual results to differ materially from those contemplated herein 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 regulations, the condition of capital markets generally, our ability to access capital markets, cyberterrorism and inadequate cybersecurity, unanticipated outages at our generation facilities, adverse results in current and future litigation, failure to identify, execute or successfully implement acquisitions, repowerings or asset sales, our ability to implement value enhancing improvements to plant operations and companywide processes, our ability to implement and execute on our publicly announced transformation plan, including any cost savings, margin enhancement, asset sale, and net debt targets, our ability to proceed with projects under development or the inability to complete the construction of such projects on schedule or within budget, risks related to project siting, financing, construction, permitting, government approvals and the negotiation of project development agreements, our ability to progress development pipeline projects, the inability to maintain or create successful partnering relationships, our ability to operate our businesses efficiently, our ability to retain retail customers, our ability to realize value through our commercial operations strategy, the ability to successfully integrate businesses of acquired companies, our ability to realize anticipated benefits of transactions (including expected cost savings and other synergies) or the risk that anticipated benefits may take longer to realize than expected, and our ability to execute our Capital Allocation Plan. Debt and share repurchases may be made from time to time subject to market conditions and other factors, including as permitted by United States securities laws. Furthermore, any common stock dividend is subject to available capital and market conditions.

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, free cash flow guidance and excess cash guidance are estimates as of February 28, 2019. These estimates are based on assumptions the company believed to be reasonable as of that date. NRG disclaims any current intention to update such guidance, 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 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.

Agenda

Business Review

Mauricio Gutierrez, President and CEO

Financial Review

Kirk Andrews, EVP and CFO

Closing Remarks

Mauricio Gutierrez, President and CEO

Q&A

Key Messages

Integrated Platform Delivers Strong and Predictable Results in 2018; Reaffirming 2019 Guidance

Well-Positioned for ERCOT Summer through Balanced Portfolio and Enhanced Summer Readiness and Plant Reliability Programs

Executing on Disciplined Capital Allocation Principles; Announcing $1 Bn Share Repurchase Program

Business Highlights

2018 Scorecard

☑ **Deliver on Financial and Operational Objectives**

- ☑ Top decile safety performance; best year in history
- ☑ Financial results upper half of guidance range
- ☑ $1.5 Bn share repurchase program complete

☑ **Execute on Transformation Plan Objectives**

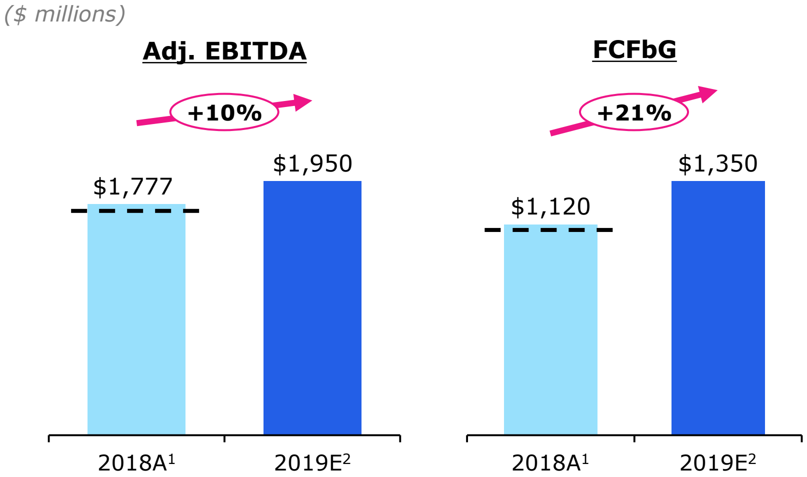
- ☑ $532 MM of EBITDA-accretive cost savings
- ☑ $32 MM of EBITDA-accretive margin enhancement
- ☑ Achieve 3.0x Net Debt/Adj. EBITDA

☑ **Complete Asset Sales, Dispositions, and Acquisitions**

- ☑ Closed on sale of NRG Yield/Renewables
- ☑ Closed on sale of South Central
- ☑ Closed on sale of Carlsbad
- ☑ Closed on sales of: BETM, Canal 3, Guam, KeyCon, Buckthorn Solar, and Spanish Town
- ☑ GenOn resolution
- ☑ Closed on acquisition of XOOM Energy

☑ **Provided Long-Term Strategy at Analyst Day**

Financial Update



Reaffirming 2019 Guidance

Announcing $1 Bn Share Repurchase Program

Announcing Up To $600 MM Reserved to Achieve Investment Grade Metrics

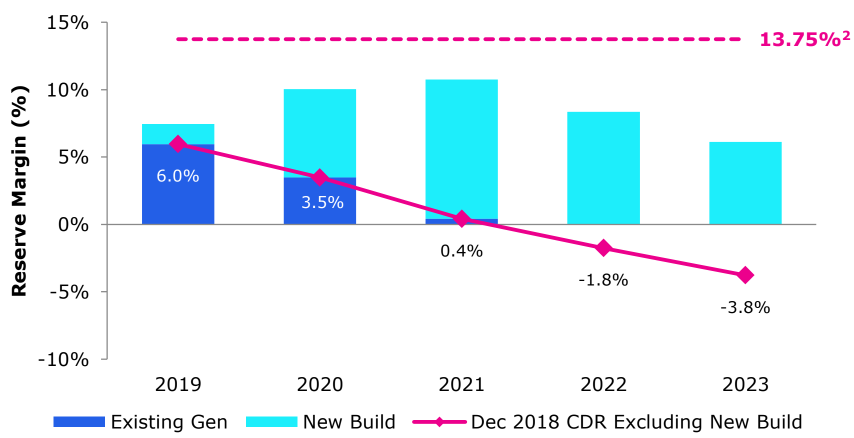
Executed on 2018 Strategic Priorities; Strong 2019 Outlook and Financial Flexibility

[1] 2018 guidance ranges: Adj. EBITDA $1,700-$1,800 MM and FCFbG $1,050-$1,150 MM; [2] Midpoint of 2019 guidance ranges

Market Update - ERCOT

Tightening Reserve Margins Require Significant New Builds

Reserve Margin Composition[1]



- All-time low reserve margins increasingly dependent on new renewables
- PUCT approves changes to ORDC to increase system reliability and attract investment
- Backwardated power prices do not support long-term investments in new generation

NRG is Well-Positioned for Summer

- **Prepared Retail** for varying price conditions
  - Customer outreach and assistance with high bills
  - Expanded Demand Response programs
- **Strengthened Generation** ahead of summer
  - Expanded Spring outage work
  - Maintaining sufficient excess generation
- **Enhanced Platform** initiatives to increase predictability
  - Positioned to acquire customers at-value
  - Complement fleet with PPA strategy
  - Opportunities to hedge beyond 2019

ERCOT Fundamentals Remain Tight;
NRG Well-Positioned to Deliver Predictable Earnings Over the Long-Term

[1] Reserve Margin sourced from Dec 2018 CDR adjusted for the indefinite mothball of Gibbons Creek (470 MW) and announced retirement of Oklaunion (650 MW); [2] Prior target Reserve Margin

Market Update - East

Key Regulatory Topics

PJM Capacity Market Reforms:

- Expect FERC to order strong MOPR with renewables exempted; in-line with PJM's request
- Outcome to be neutral to positive for NRG's fleet
- Approval timeline remains uncertain; next capacity auction, years 2022/23, in August 2019

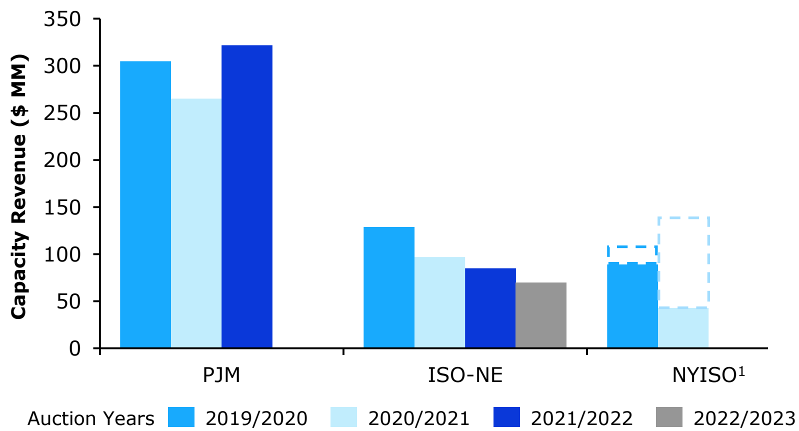
PJM Energy Market Reforms:

- Fast Start order ~5 months overdue; approval timeline remains uncertain
- PJM is expected to file positive changes to its ORDC mechanism in the near future

ISO-NE Fuel Security:

- Winter reliability at-risk (fuel security)
- Anticipate order for a short-term resolution in Spring 2019

NRG's Diverse Footprint Mitigates Exposure to ISO-NE Disappointing Auction Results

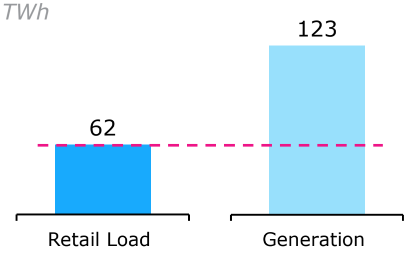
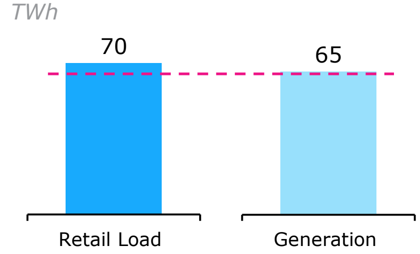


- New England's 2022/2023 capacity auction cleared at $3.80/kW-month
  - Auction results primarily driven by FERC decision to keep Mystic plant as a price-taker
  - Auction results may exacerbate fuel security issues

Regulatory and Market Reforms a Focus in the East

[1] NYISO 2019 and 2020 bilateral sales and auction results; future bilateral sales and auctions assumed to clear at current market levels

Portfolio Update

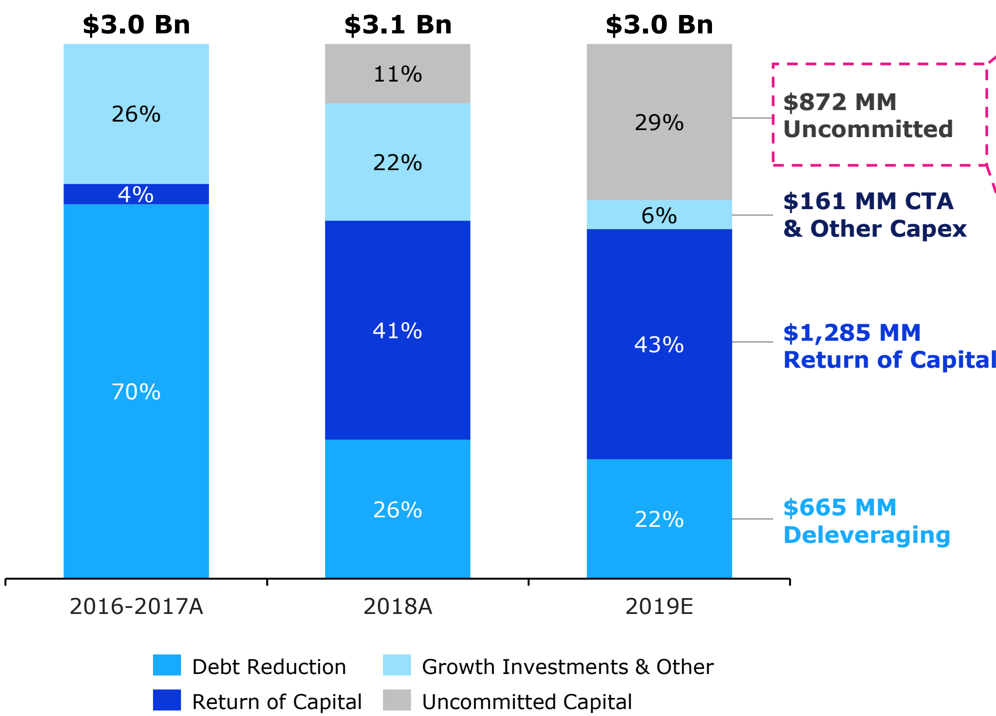
	2015	2019 Pro Forma	
1 Streamlined and Rebalanced Our Portfolio			**47%** Decrease in Generation
2 Strengthened Balance Sheet (Total Debt)	**$19.5 Bn[1]**	**$6 Bn[2]**	**69%** Decrease in Total Debt
3 Disciplined Capital Allocation with Enhanced FCF Conversion	**~25%[3]**	**~70%**	**2.8x** Increase in Conversion

Stronger and More Balanced Platform Poised to Create Significant Shareholder Value

[1] As of 12/31/2015; [2] Pro Forma 2019 corporate net debt of $5,407 MM plus $500 MM minimum cash plus $168 MM non-recourse debt; [3] NRG Level FCFbG / Consolidated Adj. EBITDA

2019 Capital Allocation Plan

Stabilize → Right-Size → Redefine



Capital Allocation Priorities

Maintain top decile safety and operational excellence

Continue to strengthen balance sheet to Investment Grade metrics of **2.50-2.75x** Net Debt / Adjusted EBITDA

Reinvest at or above hurdle rate of **12-15%** unlevered pretax return with **5-year** or less payback

Growth Investments	Return of Capital
Consistent with strategy	Share repurchases compelling at current price
Superior to implied share price return	Dividend policy to further rerate the stock

2019 Capital Allocation: Announcing $1 Bn Share Repurchase Program and Up To $600 MM Debt Reserved to Achieve Investment Grade Metrics

Financial Review

2018 Financial Summary
Maintaining 2019 Guidance

($ millions)

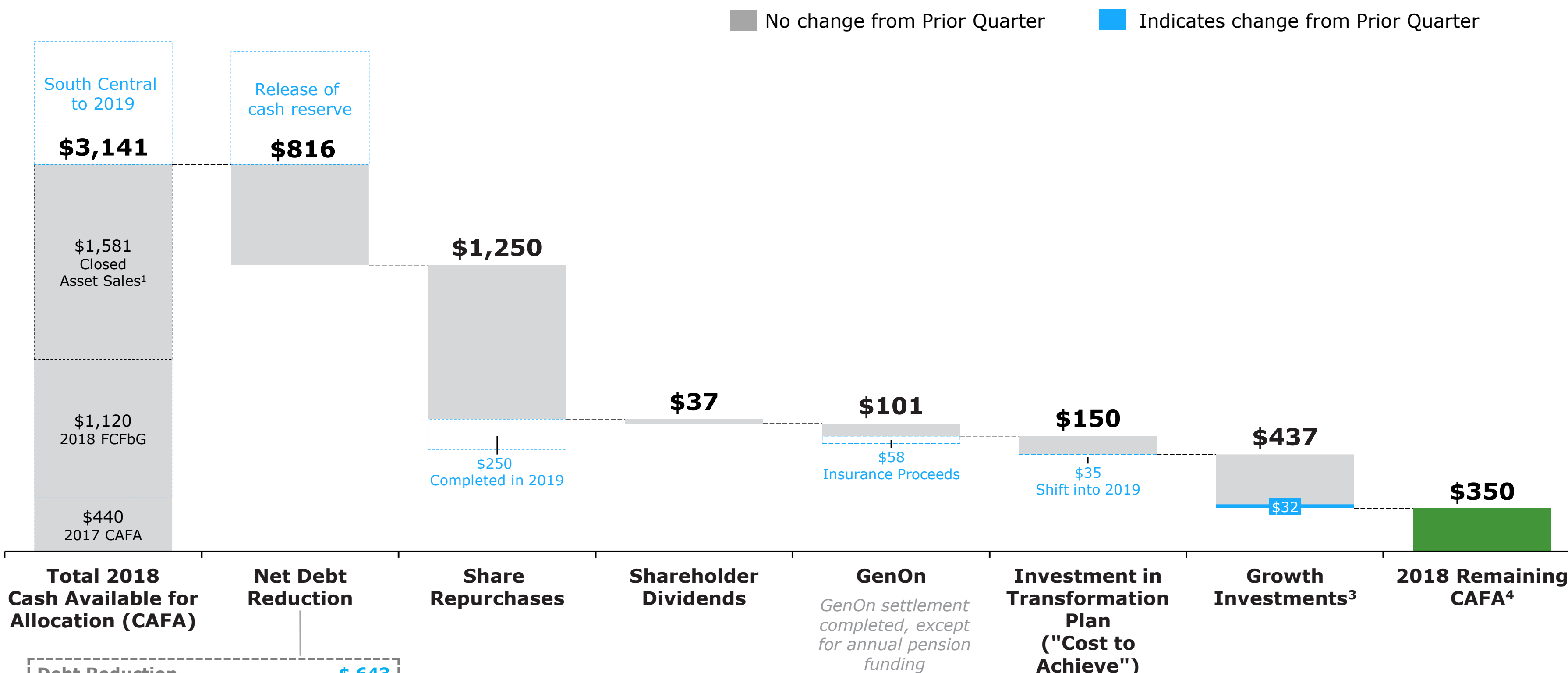
	2018 Full Year Results	2019 Guidance
Retail	$ 952	$1,000 – $1,100
Generation[1]	825	850 – 950
Adjusted EBITDA	**$1,777**	**$1,850 - $2,050**
Free Cash Flow before Growth	**$1,120**	**$1,250 - $1,450**

- Strong 2018 results as compared to 2017:
  - Retail increased by $127 MM through execution of cost reductions and margin enhancement initiatives, despite significant increases in supply costs
  - Generation[1] ~$260 MM better on higher prices and cost reduction initiatives
- Closed on sale of South Central and Carlsbad in February 2019 for a total of ~$1.4 Bn[2]
  - Results treated as discontinued operations in 2018
- Completed $640 MM of corporate debt reduction to achieve 3.0x net debt/Adj. EBITDA target in 2018
- Revising balance sheet target ratios in 2019 to maintain credit metrics consistent with Investment Grade
  - Reserving up to $600 MM in 2019 capital toward additional debt reduction
- Completed $1.5 Bn share repurchase program[3] (average price of $36.24/share)
  - Introducing new authorization of $1 Bn for share repurchases from 2019 capital

[1] Includes Corporate segment; 2018 Adj. EBITDA includes BETM through date of sale ($30 MM); 2019 Adj. EBITDA includes pro-rata share of Agua Caliente (~$40 MM); [2] See appendix slide 33 for details; excludes working capital and other adjustments; [3] $1.25 Bn completed in 2018, remaining $250 MM completed by February 2019

2018 Capital Allocation

($ millions)



Debt Reduction	$ 643
Term Loan Amortization	19
Midwest Gen Debt Amortization[2]	103
Debt Premiums and Refinancing Fees	51

~75% of 2018 Capital Allocated to Return of Shareholder Capital and Debt Reduction

[1] See appendix slide 33 for list of announced asset sales, net of transaction fees and other adjustments; [2] $103 MM of 2018 capacity revenue sold forward in 2016; 2018 payment to counterparty treated as debt amortization for accounting purposes; [3] Net of financing; [4] CAFA = 2018 YE cash & cash equivalents of $563 MM less minimum cash reserve of $500 MM (net of $287 MM in cash collateral postings)

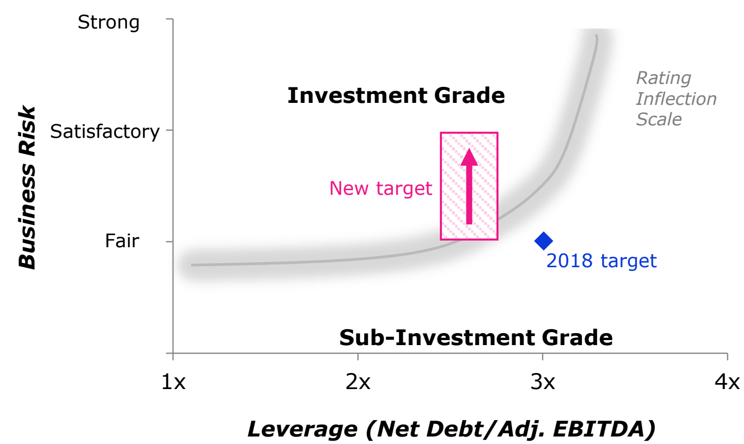
Corporate Credit Profile/New Targets

($ millions)

	2018	2019 Guidance
Corporate Debt[1]	**$6,524**	**$6,524**
2019 Term Loan Amortization	-	(17)
Corporate Debt	**$6,524**	**$6,507**
Cash & Cash Equivalents[2]	(563)	(500)
Pro Forma cash for sale of South Central[3]	(1,000)	-
Debt reduction	-	(600)
Corporate Net Debt	**$4,961**	**~$5,407**
Adj. EBITDA	**$1,777**	**$1,950**
Less: MWG Adj. EBITDA, net of cash distrib.	(98)	(30)
Other Adjustments[4]	127	150
Corporate Adj. EBITDA	**$1,806**	**$2,070**

	2018	Revised Target Ranges
Net Debt / Adj. EBITDA	**<3.0x**	**2.50 - 2.75x**
Adj. CFO[5] / Net Debt	**26.9%**	**27.5 - 32.5%**
(Adj. CFO + Interest[5]) / Interest[5]	**4.3x**	**5.5 - 6.5x**

Illustrative NRG Credit Profile



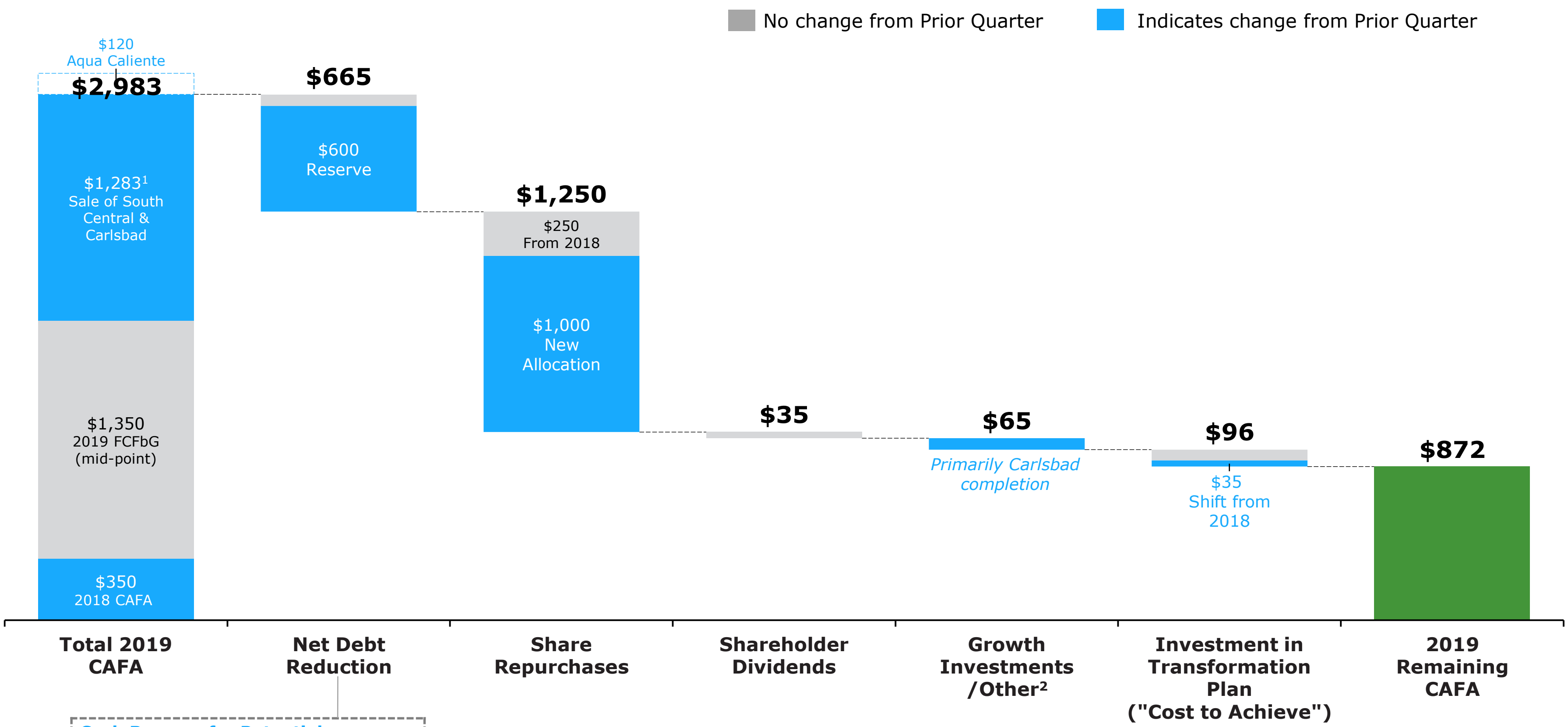
- Further enhances financial risk profile
- Reduces cost of capital
- Accretive to FCFbG (2%)

Transitioning Toward Investment Grade Metrics

[1] 2018 reflects balance at 12/31/2018; see slide 32; [2] 2019 comprises minimum cash assuming capital is fully deployed; [3] Cash received in February 2019 and included to be consistent with application of discontinued operations; [4] Includes non-cash expenses (i.e. nuclear amortization, equity compensation amortization, and bad debt expense) that are included in Adj. EBITDA; [5] See slides 36 and 37; excludes non-recourse interest; 2019 ratio assumes full year impact of ~6% interest savings associated with $600 MM of debt reduction

2019 Capital Allocation

($ millions)



Cash Reserve for Potential Debt Reduction	**$ 600**
Term Loan Amortization	17
Midwest Gen Debt Amortization[3]	48

$1 Bn Allocated to Share Repurchases with Up To $600 MM in Additional Debt Reduction to Align Balance Sheet with New Metrics

[1] See appendix slide 33 for details; net of transaction fees and other adjustments; [2] Includes $15 MM for GenOn pension funding for 2019; [3] $49 MM of 2019 capacity revenue sold forward in 2016; 2019 payment to counterparty treated as debt amortization for accounting purposes

Closing Remarks

2019 Priorities

- ☐ **Deliver on Financial and Operational Objectives**

- ☐ **Execute on NRG Transformation Plan 2019 Objectives**
  - ☐ $590 MM cumulative EBITDA-accretive cost savings
  - ☐ $135 MM cumulative EBITDA-accretive margin enhancement

- ☐ **Continue to Perfect Customer-Focused Business Model**

- ☐ **Adhere to Disciplined Capital Allocation Strategy**
  - ☐ Execute new share repurchase program of $1.0 Bn
  - ☐ Target investment grade credit metrics with up to $600 MM in deleveraging

Appendix

Transformation Plan
Scorecard Update

Scorecard as of 12/31/2018

($ millions)	2018 Realized	2018 % Achieved	2018 Target
Accretive & Recurring:			
Cost Savings	532	*106%*	500
Margin Enhancement	32	*107%*	30
Total EBITDA - Accretion	**$564**	***106%***	**$530**
Maintenance Capex	47	*157%*	30
Total Recurring FCFbG - Accretion	**$611**	***109%***	**$560**
Non-Recurring:			
Working Capital Improvement	112	*112%*	100
Cost to Achieve Total Transformation Plan	(150)	-	(185)
Total Non-Recurring	**($38)**	**-**	**($85)**
Annual Cash Accretion	**$573**	***121%***	**$475**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$900**	***112%***	**~$802**

Transformation Plan Progress

($ millions)	2017 Realized	2018 Realized	2019 Target	2020 / Run Rate
Accretive & Recurring:				
Cost Savings	150	532	590	590
Margin Enhancement*	-	32	135	215
Total EBITDA –Accretion	**$150**	**$564**	**$725**	**$805**
Maintenance Capex*	-	47	50	50
Total Recurring FCFbG Accretion	**$150**	**$611**	**$775**	**$855**
Non-Recurring:				
Working Capital Improvement[1]	221	112	37	--
Cost to Achieve Total Transformation Plan[2]	(44)	(150)	(96)	--
Total Non-Recurring	**$177**	**($38)**	**($59)**	**--**
Annual Cash Accretion	**$327**	**$573**	**$716**	**$855**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$327**	**$900**	**~$1,616**	**~$2,471**

*** On track:** no stated target in 2017 per plan announced 7/12/2017

[1] 2019 Working Capital Improvement target updated from $49 MM at 3Q18 earnings due to achievement levels in 2017 and 2018; total target did not change and remains $370 MM; [2] 2019 Cost to Achieve Total Transformation Plan target updated from $60 MM at 3Q18 earnings due to achievement levels in 2017 and 2018; total remains $290 MM

Committed to Sustainability

NRG Sustainability Framework

Sustainable Business

Sustainable Operations

Sustainable Customers

Sustainable Suppliers

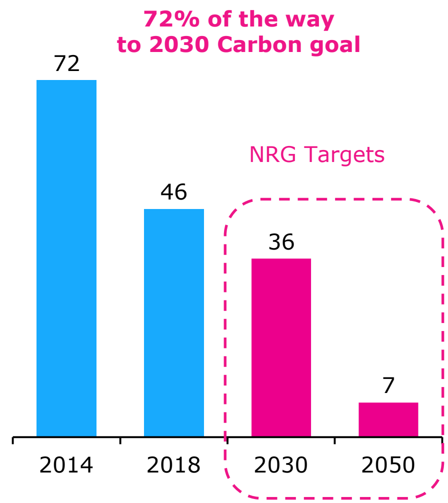
Sustainable Workplace

Industry-Leading Disclosure

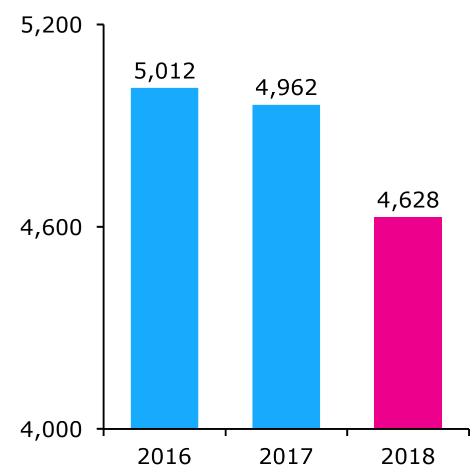
Comprehensive Approach

Environmental Leadership[1]

U.S. CO_2e Emission Goals ($MMtCO_2e$)



Revenue Carbon Intensity (tCO_2e/$ MM)



[1] NRG's goal is to reduce its total U.S. Scope 1, 2 (purchased electricity) and 3 (business travel) CO_2e emissions by 50% by 2030, and by 90% by 2050, using 2014 as a baseline

Appendix: Operations

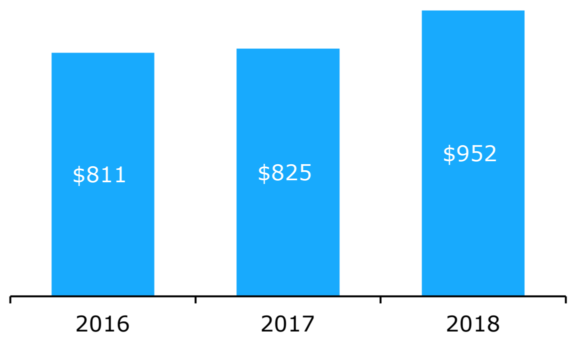
Retail: Operational Metrics

2018 Highlights

- Delivered 5th year in a row of earnings growth with $952 MM of Adjusted EBITDA in 2018
- Delivered another year of customer growth driven by the XOOM acquisition as well as organic customer acquisition and retention efforts
- Launched innovative partnerships, offers and customer service tools to extend retail leadership position in competitive markets

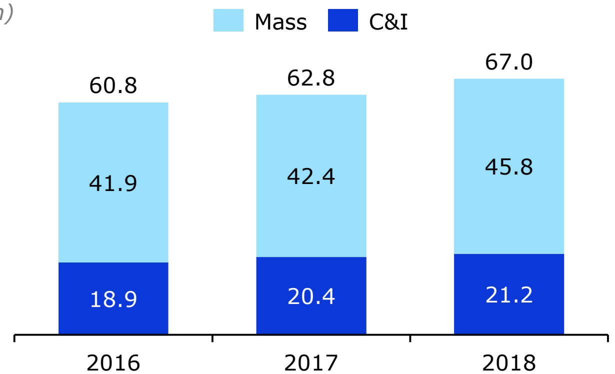
Retail Earnings

Adj. EBITDA ($ millions)



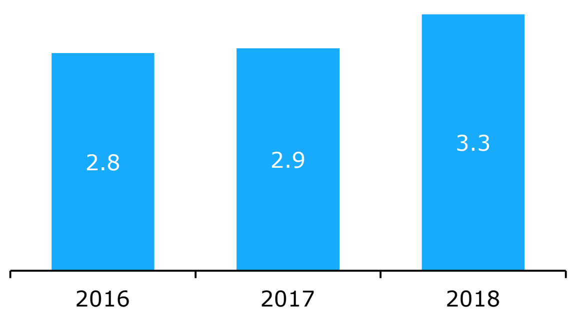
Delivered Volume

Load (TWh)



Recurring Mass Customer Count[1]

Count (millions)



Another Year of Earnings Growth for Retail

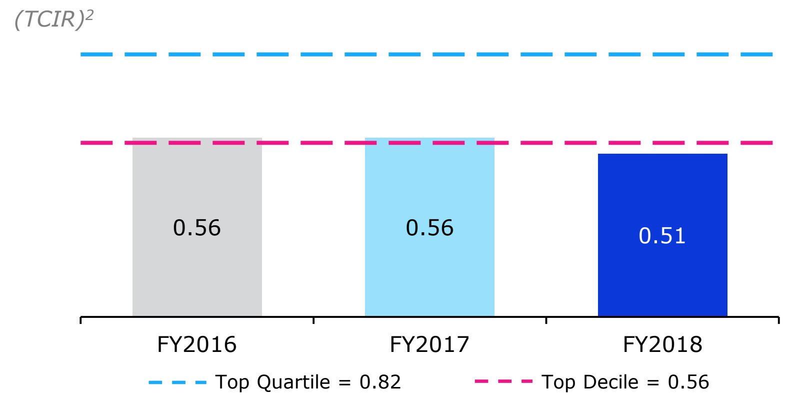
[1] Mass count includes recurring customers that subscribe to one or more recurring services, such as electricity and natural gas

Generation: Operational Metrics

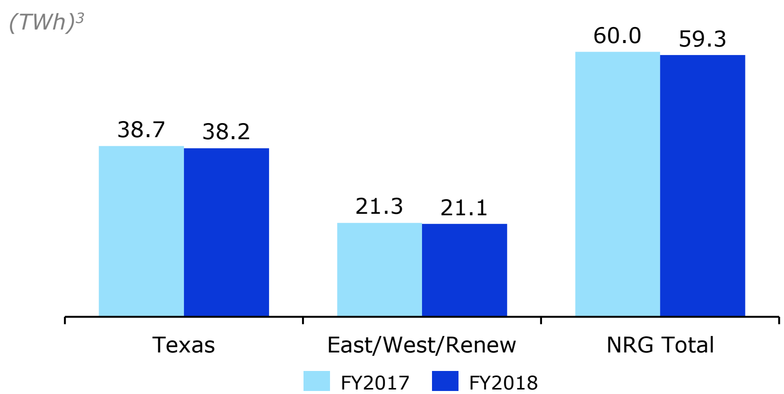
2018 Highlights

- Delivered another year of top decile safety; best performance in company history
- Delivered strong earnings with $825 MM[1] of Adjusted EBITDA in 2018; up 28% YoY
- All announced asset sales completed
- Strong plant in the money availability

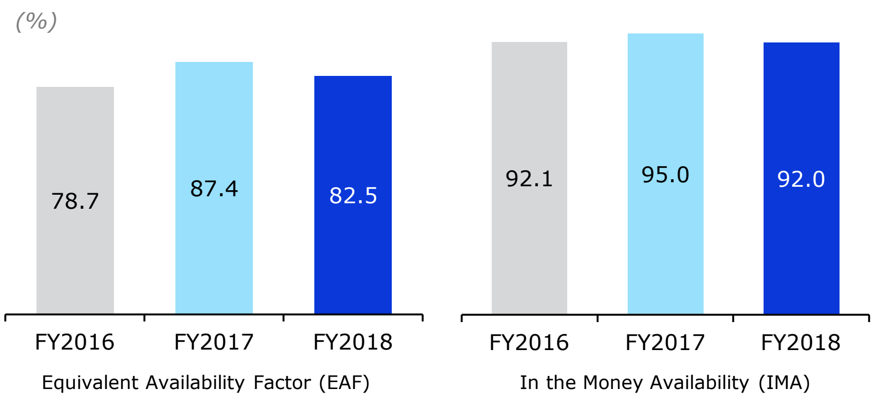
Safety[1]



Production



Baseload EAF and In the Money Availability



Solid Performance with Focus on Safety and Outage Execution

[1] Includes Corporate segment; 2018 Adj. EBITDA includes BETM through date of sale; [2] Excludes Goal Zero, NRG Home Services & Security; top decile and top quartile based on Edison Electric Institute 2016 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation; excludes line losses, station service, and other items. Generation data presented above consistent with GAAP and excludes discontinued operations

Components of Gross Margin

Open Energy Gross Margin

- Forecasted energy revenue at current market prices, net of fuel and emissions expense
- Excludes ancillary revenue
- Excludes equity interest projects, international and renewable projects
- Based on a combination of dispatch and stochastic models

Mark-to-Market of Hedges

- Current fair value of all power and fuel hedges
- Difference between current market price and transaction price; multiplied by volume of the transaction

Total Energy Gross Margin

- Total energy gross margin is the sum of open energy gross margin and MtM of hedges
- Hedges are a combination of forward power sales, gas purchases/sales and forward coal purchases; net natural gas hedge position converted to power-equivalent after adjusting for correlation between forward power and natural gas prices
- Percentage hedged is power-equivalent hedge volumes divided by estimated generation

Capacity Revenues

- Expected capacity revenues from cleared capacity auctions or sold bilaterally
- Includes forecasted revenue from unsold capacity

Wholesale Total Gross Margin

Total Wholesale Generation Portfolio[1]	ERCOT		East/West[2]	
	2019	**2020**	**2019**	**2020**
Total Capacity (MW)[3]	10,022	10,022	11,548	11,548
Estimated Generation (GWh)[4]	43,137	43,214	21,874	21,311
Percentage Hedged[5]	**92%**	**53%**	**73%**	**27%**
Gross Margin Summary ($ MM)				
Open Energy Gross Margin[6]	$1,398	$1,220	$280	$275
Mark-to-Market of Hedges[7]	($222)	($77)	$9	($6)
Total Energy Gross Margin	**$1,176**	**$1,143**	**$289**	**$269**
Capacity Revenue[8]	--	--	$601	$563
Wholesale Total Gross Margin	**$1,176**	**$1,143**	**$890**	**$832**
Gross Margin Sensitivity ($ MM)				
Gas Price Sensitivity Up $0.50/MMBtu[9]	**<$5**	**$90**	**$74**	**$124**
Gas Price Sensitivity Down $0.50/MMBtu[9]	**>($5)**	**($121)**	**($45)**	**($86)**
Heat Rate Sensitivity Up 1 MMBtu/MWh[10]	**$37**	**$99**	**$63**	**$96**
Heat Rate Sensitivity Down 1 MMBtu/MWh[10]	**($32)**	**($92)**	**($46)**	**($81)**

[1] Portfolio as of 1/31/2019, excludes equity interest, International and renewable assets
[2] Includes Cottonwood
[3] Total capacity represents net summer dependable MW capacity of plants after adjusting for the Company's ownership position excluding capacity from inactive/mothballed units
[4] Estimated generation represents expected generation dispatch output (GWh) based on forward price curves as of 1/31/2019
[5] Percentage hedged represents the portion of the portfolio that is hedged using forward power & natural gas sales contracts; any forward natural gas for power hedges are reflected in power-equivalent based on forward market implied heat rate as of 1/31/2019 after adjusting for correlation between forward power and natural gas prices which is then combined with power sales to arrive at total power-equivalent hedge volume; % hedged is based on the power-equivalent hedge volumes divided by estimated generation (4); excludes the extent of coal hedging – NRG is hedged 100% and 36% of its coal fuel requirement for 2019 & 2020 respectively
[6] Open Energy Gross Margin represents the expected revenue net of fuel and emission costs from merchant conventional fleet based upon a dispatch model that uses forward power and fuel curves and takes into account planned/unplanned outage events
[7] Mark to Market of hedges represents the current fair value of power and fuel hedges and is calculated by multiplying the difference between the current forward price and the transaction price with the volume of the transaction. This includes all inter-segment sales executed between the generation segment to retail segment; actual value of options will include the impact of non-linear factors; for detailed information on the Company's hedging methodology through use of derivative instruments, see discussion in 2018 10K Item 15 - Note 5, Accounting for Derivative Instruments and Hedging Activities
[8] Capacity revenue represents revenue from MWs cleared in ISO auctions or sold bilaterally plus forecasted revenue from unsold capacity. For details please refer to the slide on Capacity Clears & Unsold in the deck
[9] Gas Price Sensitivity represents Gross Margin change from $0.5/MMBtu gas price change, keeping heat rates unchanged
[10] Heat Rate Sensitivity represents Gross Margin change from 1 HR change in annual RTC power prices, keeping natural gas prices unchanged; the change in heat rate is shaped by the level of the current forward curve – higher priced months experience bigger changes in heat rate while lower priced months experience smaller changes

Commodity Prices

	2019		2020	
Reference Prices 1/31/2019	**Reference Price**	**Market Heat Rate**	**Reference Price**	**Market Heat Rate**
Natural Gas Henry Hub ($/MMBtu)	$2.93	--	$2.72	--
PRB 8800 Coal ($/Ton)	$12.37	--	$12.35	--
	$/MWh	**MMBtu/MWh**	**$/MWh**	**MMBtu/MWh**
ERCOT Houston Around-the-Clock ($/MWh)	$38.37	13.1	$34.87	12.8
PJM West Around-the-Clock ($/MWh)	$32.07	10.9	$32.19	11.8

Capacity Clears & Unsold

Capacity Revenue by Calendar Year ($ MM)

Market	2019	2020
PJM	$317	$282
ISO-NE	$149	$110
NYISO[1]	$105	$141
CAISO[1]	$30	$30

Illustrative: Assumes uncleared capacity clears at current market levels

Market	Region	Planning Year	Average Price ($/kW-Month)	Estimated Qualified Capacity[2]	Percentage Sold[3]	MWs Cleared
ISO-NE	Connecticut	2018-2019	$9.55	1,535	100%	1,535
		2019-2020	$7.03	1,529	100%	1,529
		2020-2021	$5.30	1,529	100%	1,529
		2021-2022	$4.63	1,529	100%	1,529
		2022-2023	$3.80	1,517	100%	1,517
NYISO		2019	$3.13	2,800	85%	2,373
		2020	$4.19	2,800	31%	857
CAISO		2019	$3.01	838	100%	838
		2020	$3.03	838	18%	150

[1] NYISO & CAISO values include sold and unsold revenue; unsold revenue is estimated as of 1/31/2019 and is subject to change; NYC estimated qualified capacity is 1.25 GW; NYISO – Rest of State estimated qualified capacity is 1.55 GW; [2] Capacity that can be bid in a capacity auction; estimated as of 1/31/2019 and is subject to change; [3] Percentage of the total qualified capacity that has been sold as of 1/31/2019

PJM Capacity Clears

Capacity Revenue by Calendar Year ($ MM)

Market	2019	2020	2021
PJM	$317	$282	$299

Capacity Revenue by Delivery Year ($ MM)

Market	18/19	19/20	20/21	21/22
PJM	$334	$305	$265	$322

			Base Product		Capacity Performance Product	
Market	**Region**	**Planning Year**	**Average Price ($/MW-Day)**	**MWs Cleared**	**Average Price ($/MW-Day)**	**MWs Cleared**
PJM	ComEd	2018-2019	$25.58	221	$215.00	3,509
		2019-2020	$182.77	65	$202.77	3,738
		2020-2021			$188.12	3,315
		2021-2022			$195.55	3,995
PJM	DPL South	2018-2019	$210.63	98	$217.08	481
		2019-2020	NA	NA	$119.77	481
		2020-2021			$187.87	519
		2021-2022			$165.73	552
PJM	PEPCO	2018-2019	NA	NA	$229.10	46
		2019-2020	NA	NA	$100.00	66
		2020-2021			$86.04	67
		2021-2022			$140.00	72
PJM	Net Total	2018-2019	$82.51	319	$220.21	4,035
		2019-2020	$182.77	65	$191.89	4,284
		2020-2021			$186.34	3,901
		2021-2022			$191.12	4,619

Assumptions:

- PJM Data as of 5/23/2018
- Represents merchant wholesale generation

Q4 2018 Generation & Operational Performance Metrics

(MWh 000's)	2018 Generation[1]	2017 Generation[1]	MWh Change	% Change	2018 EAF[2]	2018 NCF[3]	2017 EAF[2]	2017 NCF[3]
Texas	9,136	9,394	(258)	(3%)	86%	43%	92%	43%
East/West[4]	3,867	4,953	(1,087)	(22%)	75%	14%	84%	16%
Total	**13,003**	**14,348**	**(1,345)**	**(9%)**	**80%**	**27%**	**88%**	**28%**
Texas Nuclear	2,049	2,575	(527)	(20%)	79%	84%	100%	99%
Texas Coal	6,528	6,108	420	7%	87%	71%	90%	66%
East Coal	1,223	1,734	(511)	(29%)	57%	18%	76%	22%
Baseload	**9,800**	**10,417**	**(618)**	**(6%)**	**75%**	**53%**	**86%**	**54%**
Texas Gas	559	711	(152)	(21%)	86%	6%	93%	7%
East Oil	75	102	(27)	(27%)	79%	1%	80%	1%
East Gas[5]	1,623	1,617	6	0%	76%	19%	90%	19%
West Gas	934	1,156	(223)	(19%)	98%	24%	98%	29%
Intermediate / Peaking	**3,191**	**3,586**	**(396)**	**(11%)**	**83%**	**11%**	**89%**	**12%**
Renewables	**13**	**344**	**(332)**	**(96%)**				

[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor; [4] Includes Cottonwood and renewable assets. International is excluded from this table; [5] Includes the 1,263 MW Cottonwood facility

YTD 2018 Generation & Operational Performance Metrics

(MWh 000's)	2018 Generation[1]	2017 Generation[1]	MWh Change	% Change	2018 EAF[2]	2018 NCF[3]	2017 EAF[2]	2017 NCF[3]
Texas	38,214	38,694	(480)	(1%)	85%	45%	90%	45%
East/West[4]	21,089	21,338	(250)	(1%)	83%	18%	85%	17%
Total	**59,302**	**60,032**	**(730)**	**(1%)**	**84%**	**30%**	**88%**	**29%**
Texas Nuclear	9,018	9,509	(492)	(5%)	90%	90%	94%	92%
Texas Coal	24,781	24,757	24	0%	86%	68%	91%	67%
East Coal	7,965	8,403	(438)	(5%)	75%	27%	80%	27%
Baseload	**41,764**	**42,670**	**(906)**	**(2%)**	**82%**	**56%**	**87%**	**56%**
Texas Gas	4,415	4,428	(13)	(0%)	83%	11%	89%	11%
East Oil	544	319	225	70%	86%	2%	86%	1%
East Gas[5]	8,808	7,525	1,284	17%	86%	26%	87%	22%
West Gas	2,989	3,424	(436)	(13%)	90%	19%	92%	22%
Intermediate / Peaking	**16,755**	**15,696**	**1,060**	**7%**	**86%**	**14%**	**88%**	**13%**
Renewables	**783**	**1,667**	**(884)**	**(53%)**				

[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor; [4] Includes Cottonwood and renewable assets. International is excluded from this table; [5] Includes the 1,263 MW Cottonwood facility

Asset List[1]

ERCOT

ERCOT (10,041 MW, Net)		
Name	Capacity	Ownership
Cedar Bayou	1,494	100%
Cedar Bayou 4	252	50%
Elbow Creek (Battery Storage)	2	100%
Greens Bayou	330	100%
Gregory	365	100%
Limestone	1,660	100%
Petra Nova[2]	19	50%
San Jacinto	160	100%
South Texas	1,126	44%
T.H. Wharton	1,001	100%
W.A. Parish	3,632	100%

MISO

MISO (1,263 MW, Net)		
Name	Capacity	Ownership
Cottonwood	1,263	Lease thru 2025

CAISO

CAISO (1,155 MW, Net)		
Name	Capacity	Ownership
Long Beach	252	100%
Midway Sunset[2]	113	50%
Sunrise	586	100%
Watson[2]	204	49%

PJM

ComEd (4,328 MW, Net)		
Name	Capacity	Ownership
Fisk	171	100%
Joliet	1,326	100%
Powerton	1,538	100%
Waukegan	783	100%
Will County	510	100%

DPL (593 MW, Net)		
Name	Capacity	Ownership
Indian River	426	100%
Vienna	167	100%

PEPCO (80 MW, Net)		
Name	Capacity	Ownership
Chalk Point (SMECO)	80	100%

NYISO

NYC (1,280 MW, Net)		
Name	Capacity	Ownership
Arthur Kill	865	100%
Astoria	415	100%

Central (1,638 MW, Net)		
Name	Capacity	Ownership
Oswego	1,638	100%

ISO-NE

Connecticut (1,528 MW, Net)		
Name	Capacity	Ownership
CT Jets	142	100%
Devon	133	100%
Middletown	762	100%
Montville	491	100%

Renewables

Renewables (457 MW, Net)		
Name	Capacity	Ownership
Agua Caliente[2]	102	35%
Ivanpah[2]	214	55%
Sherbino Wind[2]	75	50%
Stadiums	6	100%
Resi-Solar	60	100%

International

International (749 MW, Net)		
Name	Capacity	Ownership
Gladstone[2]	605	38%
Doga	144	80%

[1] As of 2/28/2019; [2] Equity investments

Appendix: Finance

Q4 2018 YTD Net Capital Expenditures

($ millions)	Maintenance	Environmental	Growth[1]	Total
Retail	$19	-	$71	$90
Generation				
Gulf Coast	77	-	-	77
East/West[2]	54	1	135	190
Corporate	9	-	22	31
Total Cash Capital Expenditures	**$159**	**$1**	**$228**	**$388**
XOOM acquisition and integration	-	-	208	208
Other Investments[3]	-	-	176	176
Project Funding, net of fees[4]	-	-	(118)	(118)
Total Capital Expenditures and Growth Investments, net (including CTA)	**$159**	**$1**	**$494**	**$654**
Total Capital Expenditures and Growth Investments, net (excluding CTA capex)	***$159***	***$1***	***$437***	***$597***

[1] Includes cost-to-achieve spend of $57 MM; [2] Includes International and renewables, and capital spend related to Canal 3; [3] Includes Retail small book acquisitions, Carlsbad, and equity investment fundings; [4] Includes $84 MM of UPMC sales proceeds (dropped down to Clearway Energy, Inc. prior to sale to GIP) and $34 MM of the Canal 3 debt financing proceeds (remaining proceeds treated as asset sale / financing proceeds in capital allocation)

Recourse / Non-Recourse Debt

($ millions)	12/31/2018	9/30/2018	6/30/2018	3/31/2018
Recourse Debt				
Term Loan Facility	$ 1,698	$ 1,857	$ 1,862	$ 1,867
Senior Notes	3,784	4,269	4,801	4,845
Convertible Notes	575	575	575	-
Tax Exempt Bonds	466	466	465	465
Revolver	-	-	26	-
Capital Lease	1	2	4	4
Corporate Debt Subtotal	**$ 6,524**	**$ 7,169**	**$ 7,733**	**$ 7,181**
Non-Recourse Debt				
NRG Yield[1]	-	-	5,970	6,038
Renewables[1] (including capital leases)	115	185	1,735	2,756
Conventional[2]	53	84	657	613
Non-Recourse Debt Subtotal	**$ 168**	**$ 269**	**$ 8,362**	**$ 9,407**
Total Debt	**$ 6,692**	**$ 7,438**	**$ 16,095**	**$ 16,588**

Note: Debt balances exclude discounts and premiums
[1] Balance as of 12/31/2018 includes $86 MM of Agua Borrower I debt; balances as of 6/30/2018 and 3/31/2018 includes debt associated with NRG's interest in NRG Yield and the Renewables platform; [2] Includes Midwest Gen capacity monetization debt

Announced Asset Sales

($ millions)

	Status	2017	2018	2019	Total
Transformation Plan Asset Sales[1]:					
Asset Sales in 2H17[2]	Closed	$150	$-	$-	$150
Renewables / NRG Yield Interest	Closed	-	1,348	-	1,348
Buckthorn Solar	Closed	-	42	-	42
BETM	Closed	-	70	-	70
Other[3]	Closed	-	24	8	32
South Central	Closed	-	-	1,000	1,000
Carlsbad	Closed	-	-	387	387
Transformation Plan Total Proceeds		**150**	**1,484**	**1,395**	**3,029**
Asset Sales Outside of Transformation Plan:					
Canal 3[4]	Closed	-	130	-	130
Total Net Proceeds		**$150**	**$1,614**	**$1,395**	**$3,159**

[1] Excludes working capital, transaction fees and other adjustments totaling ~$145 MM; [2] Includes drop down proceeds for TE Holdco (25%) $42 MM and SPP $71 MM to Clearway Energy, Inc. and sale proceeds for MN Wind $37 MM; [3] Includes Spanish Town, Keystone & Conemaugh, Eastridge, Saguaro and Guam; [4] Canal 3 reflects sale and debt proceeds in excess of the original growth investment guidance

Incremental Transformation Plan

($ millions)

	2017A	2018A	2019E	2020E
Cost Savings	$150	$532	$590	$590
Margin Enhancements	-	32	135	215
EBITDA Impact	**$150**	**$564**	**$725**	**$805**
Maintenance Capex	-	47	50	50
Working Capital	221	112	37	-
FCFbG Impact	**$371**	**$723**	**$812**	**$855**
Incremental EBITDA Change		*414*	*161*	*80*
Incremental FCFbG Change		*352*	*89*	*43*

Appendix: Reg. G Schedules

Reg. G: 2018 Free Cash Flow before Growth

($ millions)		Full Year 2018
Adjusted EBITDAR	**$**	**1,799**
Less: EME operating lease expense		(22)
Adjusted EBITDA	**$**	**1,777**
Interest payments		(448)
Income tax		(9)
Collateral / working capital / other		(317)
Cash Flow from Operations (continuing operations)	**$**	**1,003**
Gain on Sale of Land		4
Cost-to-Achieve[1]		92
GenOn Settlement[2]		75
Collateral[3]		117
M&A Integration Expenses[4]		5
Adjusted Cash Flow from Operations	**$**	**1,296**
Maintenance capital expenditures, net		(159)
Environmental capital expenditures, net		(1)
Distributions to non-controlling interests		(16)
Consolidated Free Cash Flow before Growth	**$**	**1,120**

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Total Change in Working Capital & Other	
2018 Actuals (sum of a)	($24)
Less: Adjustments	21
2018 Actuals Adj.	**($ 3)**
Original guidance	(115)
2018 Improvement	**$112**
2018 Transformation Target	*$100*

[1] Includes costs associated with the Transformation Plan announced on 7/12/2017, and excludes Capex; [2] Includes settlement consideration of $261 MM, transition services credit of $28 MM, pension contribution of $13 MM, less $151 MM repayment of intercompany revolver loan, $58 MM of insurance proceeds, net of legal fees, and accrued interest and fees of $12 MM, certain other balances due to NRG of $6 MM; [3] Includes $15 MM return of collateral to GenOn; [4] Includes costs associated with acquisition and integration of XOOM

Reg. G: 2018 and 2019 Guidance

Appendix Table A-1: 2018 and 2019 Guidance

The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

($ millions)	2018 Guidance	2019 Guidance
Total Adjusted EBITDA	**$1,700 - $1,800**	**$1,850 - $2,050**
Interest payments	(445)	(350)
Income tax	(15)	(15)
Working capital / other assets and liabilities	0	(80)
Adjusted Cash Flow from Operations	**$1,240 - $1,340**	**$1,405 - $1,605**
Maintenance capital expenditures, net	(170) - (180)	(145) – (165)[1]
Environmental capital expenditures, net	(0) - (5)	(0) - (5)
Distributions to non-controlling interests	(10) - (20)	-
Free Cash Flow before Growth	**$1,050 - $1,150**	**$1,250 - $1,450**

[1] Includes ~$25 MM for TX reliability projects and inclusion of Cottonwood

Reg. G

Appendix Table A-2: Fourth Quarter 2018 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	Texas	East/ West [1]	Generation	Retail	Corp/ Elim	Total
Income/(Loss) from Continuing Operations	**(174)**	**(83)**	**(257)**	**331**	**(167)**	**(93)**
Plus:						
Interest expense, net	-	9	9	1	107	117
Income tax	-	-	-	-	(12)	(12)
Loss on debt extinguishment	-	-	-	-	21	21
Depreciation and amortization	21	31	52	30	9	91
ARO Expense	1	3	4	-	-	4
Contract amortization	7	-	7	-	-	7
Lease amortization	-	(2)	(2)	-	-	(2)
EBITDA	**(145)**	**(42)**	**(187)**	**362**	**(42)**	**133**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	4	26	30	-	-	30
Acquisition-related transaction & integration costs	-	-	-	1	1	2
Reorganization costs[2]	1	-	1	5	31	37
Legal Settlement	-	10	10	-	-	10
Deactivation costs	-	-	-	-	4	4
Gain on sale of assets	-	-	-	-	(1)	(1)
Other non-recurring charges	(1)	1	-	1	(1)	-
Impairments	5	4	9	1	-	10
Mark to market (MtM) (gains)/losses on economic hedges	153	68	221	(173)	-	48
Adjusted EBITDA	**17**	**67**	**84**	**197**	**(8)**	**273**

[1] Includes International, remaining renewables and Generation eliminations; [2] Includes $17 MM of non-recurring pension expense

Reg. G

Appendix Table A-3: Fourth Quarter YTD 2018 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	Texas	East/ West [1]	Generation	Retail	Corp/ Elim	Total
Income/(Loss) from Continuing Operations	**(102)**	**95**	**(7)**	**1,062**	**(595)**	**460**
Plus:						
Interest expense, net	-	55	55	3	408	466
Income tax	-	-	-	1	6	7
Loss on debt extinguishment	-	-	-	-	44	44
Depreciation and amortization	85	187	272	116	33	421
ARO Expense	21	15	36	1	-	37
Contract amortization	26	1	27	-	-	27
Lease amortization	-	(8)	(8)	-	-	(8)
EBITDA	**30**	**345**	**375**	**1,183**	**(104)**	**1,454**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	9	73	82	-	1	83
Acquisition-related transaction & integration costs	-	-	-	2	5	7
Reorganization costs[2]	3	8	11	15	81	107
Legal Settlement	13	10	23	-	6	29
Deactivation costs	-	10	10	-	12	22
Gain on sale of assets	-	(2)	(2)	-	(30)	(32)
Other non-recurring charges	(1)	6	5	4	(2)	7
Impairments	20	93	113	1	-	114
Mark to market (MtM) (gains)/losses on economic hedges	172	67	239	(253)	-	(14)
Adjusted EBITDA	**246**	**610**	**856**	**952**	**(31)**	**1,777**

[1] Includes International, remaining renewables and Generation eliminations; [2] Includes $17 MM of non-recurring pension expense

Reg. G

Appendix Table A-4: Quarterly 2018 Adjusted EBITDA Reconciliation by Operating Segment

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	Q1 2018	Q2 2018	Q3 2018	Q4 2018	Total 2018
Income/(Loss) from Continuing Operations	**238**	**27**	**288**	**(93)**	**460**
Plus:					
Interest expense, net	112	121	116	117	466
Income tax	6	6	7	(12)	7
Loss on debt extinguishment	2	2	19	21	44
Depreciation and amortization	120	112	98	91	421
ARO Expense	11	9	13	4	37
Contract amortization	6	7	7	7	27
Lease amortization	(2)	(2)	(2)	(2)	(8)
EBITDA	**493**	**282**	**546**	**133**	**1,454**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	8	18	27	30	83
Acquisition-related transaction & integration costs	4	1	-	2	7
Reorganization costs[1]	20	23	27	37	107
Legal Settlement	-	19	-	10	29
Deactivation costs	5	10	3	4	22
Gain on sale of assets	-	(16)	(15)	(1)	(32)
Other non-recurring charges	3	2	2	-	7
Impairments	9	102	(7)	10	114
Mark to market (MtM) (gains)/losses on economic hedges	(206)	76	68	48	(14)
Adjusted EBITDA	**336**	**517**	**651**	**273**	**1,777**

[1] Includes $17 MM of non-recurring pension expense

Reg. G

Appendix Table A-5: Fourth Quarter 2017 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	Texas	East/ West [1]	Generation	Retail	Corp/ Elim	Total
Income/(Loss) from Continuing Operations	**(1,487)**	**(231)**	**(1,718)**	**497**	**(169)**	**(1,390)**
Plus:						
Interest expense, net	-	22	22	2	97	121
Income tax	-	-	-	-	(47)	(47)
Loss on debt extinguishment	-	-	-	-	49	49
Depreciation and amortization	42	67	109	29	8	146
ARO Expense	11	13	24	-	-	24
Contract amortization	10	-	10		1	11
Lease amortization	-	(2)	(2)	-	-	(2)
EBITDA	**(1,424)**	**(131)**	**(1,555)**	**528**	**(61)**	**(1,088)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	2	-	2	-	1	3
Acquisition-related transaction & integration costs	-	-	-	-	1	1
Reorganization costs	3	4	7	6	12	25
Legal Settlement	-	-	-	(1)	-	(1)
Deactivation costs	3	6	9	-	2	11
Gain on sale of assets	-	(8)	(8)	-	-	(8)
Other non-recurring charges	-	(3)	(3)	-	(1)	(4)
Impairments	1,336	205	1,541	8	5	1,554
Mark to market (MtM) (gains)/losses on economic hedges	114	21	135	(331)	-	(196)
Adjusted EBITDA	**34**	**94**	**128**	**210**	**(41)**	**297**

[1] Includes International, remaining renewables and Generation eliminations

Reg. G

Appendix Table A-6: Fourth Quarter YTD 2017 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	Texas	East/ West [1]	Generation	Retail	Corp/ Elim	Total
Income/(Loss) from Continuing Operations	**(1,485)**	**(117)**	**(1,602)**	**873**	**(616)**	**(1,345)**
Plus:						
Interest expense, net	1	96	97	5	445	547
Income tax	-	2	2	(8)	(38)	(44)
Loss on debt extinguishment	-	-	-	-	49	49
Depreciation and amortization	183	271	454	110	32	596
ARO Expense	21	23	44	-	-	44
Contract amortization	30	4	34	1	-	35
Lease amortization	-	(8)	(8)	-	-	(8)
EBITDA	**(1,250)**	**271**	**(979)**	**981**	**(128)**	**(126)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	17	43	60	-	(10)	50
Acquisition-related transaction & integration costs	-	-	-	-	4	4
Reorganization costs	4	6	10	11	23	44
Legal Settlement	-	-	-	(1)	-	(1)
Deactivation costs	4	8	12	-	9	21
Gain on sale of assets	-	(15)	(15)	-	(1)	(16)
Other non-recurring charges	(13)	(2)	(15)	3	18	6
Impairments	1,378	223	1,601	8	4	1,613
Mark to market (MtM) (gains)/losses on economic hedges	(73)	44	(29)	(177)	-	(206)
Adjusted EBITDA	**67**	**578**	**645**	**825**	**(81)**	**1,389**

[1] Includes International, remaining renewables and Generation eliminations

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Appendix Table A-7: 2018 and 2019 Adjusted EBITDA Guidance Reconciliation: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

	2018 Adjusted EBITDA Guidance		2019 Adjusted EBITDA Guidance	
($ millions)	**Low**	**High**	**Low**	**High**
Income from Continuing Operations[1]	405	505	925	1,125
Income tax	15	15	15	15
Interest Expense	445	445	350	350
Depreciation, Amortization, Contract Amortization, and ARO Expense	490	490	430	430
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	65	65	80	80
Other Costs[2]	280	280	50	50
Adjusted EBITDA	**$1,700**	**$1,800**	**$1,850**	**$2,050**

[1] For purposes of guidance, discontinued operations are excluded and fair value adjustments related to derivatives are assumed to be zero; [2] 2018 includes impairments, loss on debt extinguishment, deactivation costs, and cost-to-achieve expenses; 2019 includes deactivation costs and cost-to-achieve expenses

Reg. G

Appendix Table A-8: Retail 2016 Adjusted EBITDA Reconciliation
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	**2016**
Net Income	**1,053**
Plus:	
Income tax	1
Depreciation, Amortization and Contract amortization	118
EBITDA	**1,172**
Loss on sale of business	1
Other non-recurring charges	2
Impairments	1
Mark to market (MtM) losses on economic hedges	(365)
Adjusted EBITDA	**811**

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Appendix Table A-9: Full Year 2018 and 2019 Adjusted EBITDA Reconciliation for Midwest Gen

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	2018	2019
Net income	**54**	**95**
Plus:		
Interest Expense	3	-
Depreciation, Amortization, Contract Amortization, and ARO Expense	38	40
EBITDA	**95**	**135**
Deactivation costs	2	-
Asset Write-offs and Impairments	2	
Mark to market (MtM) losses on economic hedges	(7)	-
Plus: Operating lease expense	22	22
Adjusted EBITDAR	**114**	**157**
Less: Operating lease expense	(22)	(22)
Adjusted EBITDA	**$92**	**$135**

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. As NRG defines it, Adjusted EBITDA represents EBITDA excluding impairment losses, gains or losses on sales, dispositions or retirements of assets, any mark-to-market gains or losses from accounting for derivatives, adjustments to exclude the Adjusted EBITDA related to the non-controlling interest, gains or losses on the repurchase, modification or extinguishment of debt, the impact of restructuring and any extraordinary, unusual or non-recurring items plus adjustments to reflect the Adjusted EBITDA from our unconsolidated investments. 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.

Management believes Adjusted EBITDA is useful to investors and other users of NRG's financial statements in evaluating its operating performance because it provides an additional tool to compare business performance across companies and across periods and adjusts for items that we do not consider indicative of NRG's future operating performance. This measure is widely used by debt-holders to analyze operating performance and debt service capacity and by equity investors to measure our operating performance without regard to items such as interest expense, taxes, depreciation and amortization, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired. Management uses Adjusted EBITDA as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends, as a measure for planning and forecasting overall expectations, and for evaluating actual results against such expectations, and in communications with NRG's Board of Directors, shareholders, creditors, analysts and investors concerning its financial performance.

Reg. G

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, as well as the add back of merger, integration and related restructuring costs. 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. The Company adds back merger, integration related restructuring costs as they are one time and unique in nature and do not reflect ongoing cash from operations and they are fully disclosed to investors.

Free cash flow (before Growth investments) is adjusted cash flow from operations less maintenance and environmental capital expenditures, net of funding, preferred stock dividends and distributions to non-controlling interests 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 free cash flow before Growth investments as a measure of cash available for discretionary expenditures.

Free Cash Flow before Growth Investment is utilized by Management in making decisions regarding the allocation of capital. Free Cash Flow before Growth Investment is presented because the Company believes it is a useful tool for assessing the financial performance in the current period. In addition, NRG’s peers evaluate cash available for allocation in a similar manner and accordingly, it is a meaningful indicator for investors to benchmark NRG's performance against its peers. Free Cash Flow before Growth Investment is a performance measure and is not intended to represent net income (loss), cash from operations (the most directly comparable U.S. GAAP measure), or liquidity and is not necessarily comparable to similarly titled measures reported by other companies.