NRG Energy Inc.

Third Quarter 2017 Earnings Presentation

November 2, 2017

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, including wind and solar performance, 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, 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 timing or completion of the GenOn restructuring, 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 and the creation of NRG Yield, 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, our ability to close the Drop Down transactions with NRG Yield, 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 and free cash flow guidance are estimates as of November 2, 2017. 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 Update
Kirk Andrews, EVP and CFO

Closing Remarks
Mauricio Gutierrez, President and CEO

Q&A

Key Messages

Transformation Plan on Track: Achieved $92 MM (142%) of 2017 cost savings target; currently anticipating 100% sale of our interest in NRG Yield and Renewables Platform

Initiating 2018 Financial Guidance: Guidance range in-line with the Transformation Plan targets

Increasingly Robust Market Fundamentals: Improving fundamentals in ERCOT market; multiple regulatory initiatives highlight urgency of market reforms

Transformation Plan
2017 Score Card, as of 9/30/2017

Transformation Plan Update

1. Cost and Margin Enhancements:

☑ Reaffirming full plan targets: $855 MM[1] of recurring FCFbG-accretion by 2020

☑ Realized $92 MM of costs savings (142% of 2017 target) as of 3Q17; ahead of schedule

❑ EBITDA margin enhancement underway; impact starting in 2018

2. Portfolio Optimization:

☑ Reaffirming asset sale proceeds target of up to $4 Bn

➢ **Update:** Vast majority of net cash proceeds expected to be announced in 2017, with balance in 2018

➢ **Update:** NRG Yield/Renewables Platform process on track for end of year announcement; currently anticipating 100% sale

3. Capital Allocation:

☑ Continued deleveraging: Retired $398 MM 2018 maturities, $206 MM 2021 maturities

Score Card, as of 9/30/2017

Year-to-Date 2017 Progress

($ millions)	YTD Realized	% achieved	2017 Target
Accretive & Recurring:			
Cost Savings	92	142%	65
Margin Enhancement*	-	-	0
Total EBITDA - Accretion	**92**	**142%**	**$65**
Maintenance Capex*	-	-	0
Total Recurring FCFbG - Accretion	**$92**	**142%**	**$65**
Non-Recurring:			
Working Capital Improvement	89	51%	175
Cost to Achieve Total Transformation Plan	(20)	17%	(115)
Total Non-Recurring	**$69**	**-**	**$60**
Annual Cash Accretion	**$161**	**129%**	**$125**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$161**	**129%**	**$125**

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

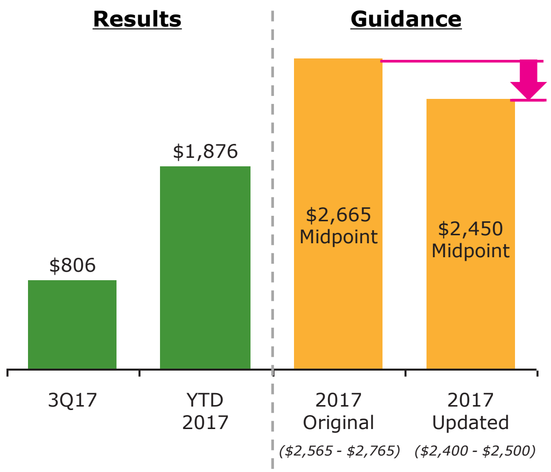
Transformation Plan On Track with $92 MM in Cost Savings to Date and Vast Majority of Asset Sale Net Cash Proceeds Announced by Year End 2017

[1] Post asset divestitures

Q3 Business Update

Announcing Third Quarter Results and Updated 2017 Guidance

Adjusted EBITDA ($MM)



Drivers:
- Mild weather
- Hurricane Harvey
- Reduced volatility

- ☑ Achieved top decile safety performance
- ☑ Q3 results impacted by Hurricane Harvey, lower power pricing due to mild weather, and reduced volatility
- ☑ Executed capital recycling with NRG Yield: Closed drop down of 38 MW portfolio of solar assets for $71 MM; announcing offer of 154 MW Buckthorn Solar asset; formed new $50 MM solar partnership

Initiating 2018 Guidance

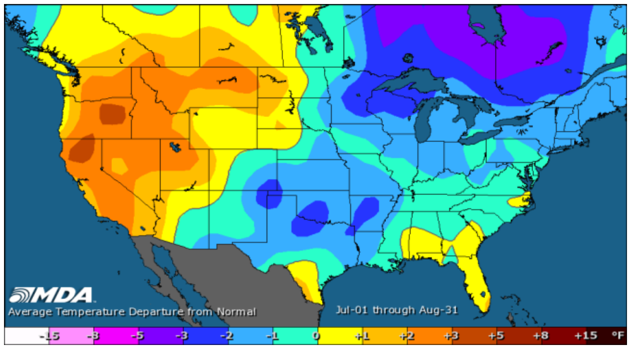
($ millions)	**2018E Guidance**
Adjusted EBITDA *pro forma post asset sales*	**$2,800 - $3,000** ~$1,500
Free Cash Flow Before Growth *pro forma post asset sales*	**$1,550 - $1,750** ~$980

Guidance Range In-Line with Transformation Plan Targets

Third Quarter Results Reflect Mild Weather and Impacts of Hurricane Harvey; Introducing 2018 Guidance at Transformation Plan Targets

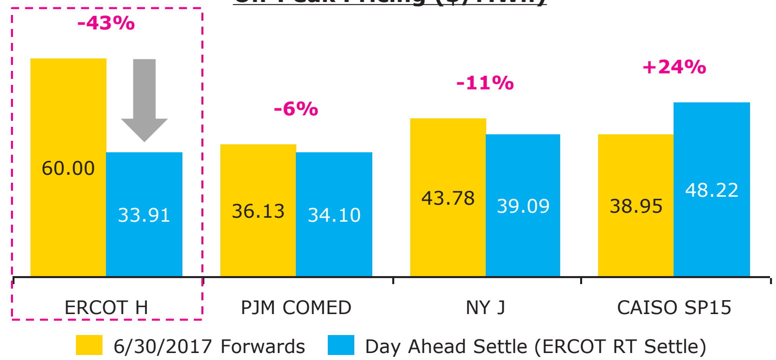
Summer 2017 Review

Milder than Average Temperatures through July and August in Core Markets…



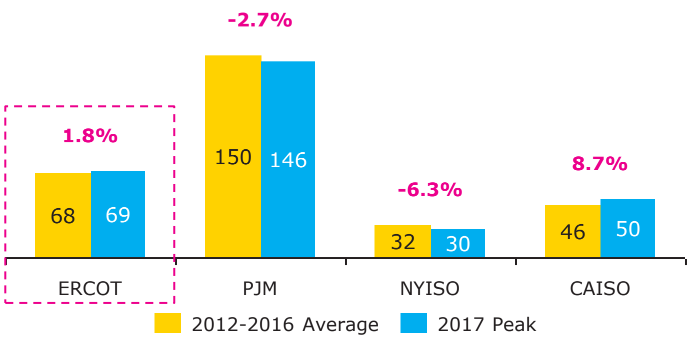
…Leads to Lower July and August Settled Prices Particularly in ERCOT…

On-Peak Pricing ($/MWh)



…But Peak Demand Remains Strong Despite Mild Weather

Peak Demand (GW)



Summer 2017 Highlights

- ERCOT experienced an extremely mild summer with August CDDs at lowest level since 2004:
  - Realized pricing fell 43% below pre-summer expectations
  - However, on-peak and around-the-clock power demand remained robust supporting strong fundamentals
- NRG demonstrated operational resiliency during Hurricane Harvey

Mild Weather Across ERCOT and Northeast Dampens Prices; Peak Load Growth Remains Strong in ERCOT

Hurricane Harvey Update

NRG Gulf Coast Generation	
Operational Impact:	➢ **Availability: ~80%** of NRG's baseload generation in Gulf Coast available during the worst part of the storm; **95%** of all 13 GW of generation restored today ➢ **Cottonwood (1,263 MW):** Back online; evacuated after storm, impacted by floods ➢ **Greens Bayou (330 MW)/Gregory (388 MW):** Offline; impacts still being assessed
Financial Impact:	➢ One-time financial impact $20 MM in 2017

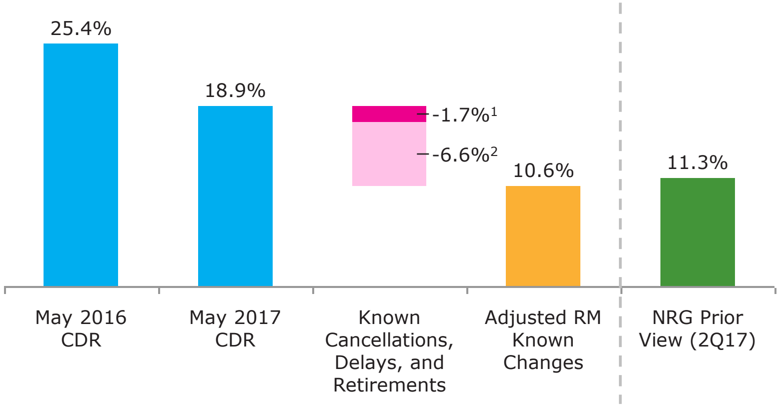
NRG Retail (Texas)	
Operational Impact:	➢ **Power Outages:** Primarily mild temperature event, not a power outage event. NRG customer outages peaked at **4%** of customers; current outages at **0.02%** customers ➢ **Customer Support:** First retailer to provide customer relief; ceased disconnects and provided customers with payment relief; engaged with the community and first responders to provide resources and power to assist customers in recovery across the Texas coast
Financial Impact:	➢ One-time financial impact $20 MM in 2017

No Reportable Safety Events at Plants or in Corporate Offices During Storm

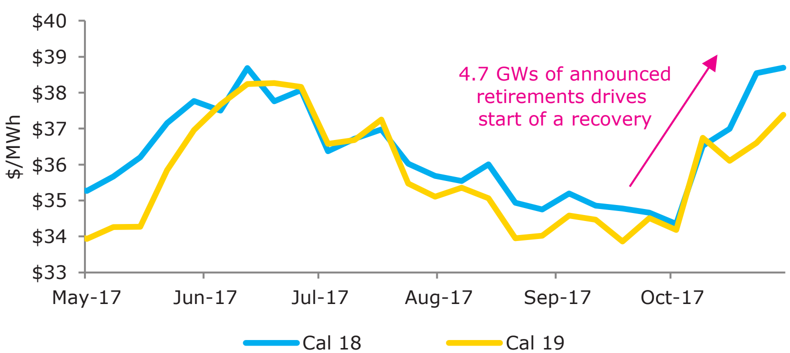
Market Outlook

ERCOT: Tightening Reserve Margins Leading to Increased Prices

ERCOT 2018 Reserve Margin (RM)



ERCOT-Houston On-Peak Pricing[3]



Regulatory: Multiple Indications for Market Reform

- **DOE Notice of Proposed Rulemaking (NOPR):** Brings renewed focus and sense of urgency to implementing energy market reforms
- **PJM Energy Market Reforms:** Focus on price formation to better reflect reliability costs by allowing inflexible units to set price
- **Out-of-Market Subsidies for Uneconomic Generation:** Ongoing litigation; confident that states are not legally permitted to replace the FERC-jurisdictional rate, as IL and NY have done
- **ERCOT Energy Market Reforms:** Low prices and stakeholder process prompting PUCT discussions on energy price formation; variety of stakeholders have expressed support for improvements

ERCOT Market Significantly Tightening After Expected Retirements; Strong Call to Action on Market Reform

[1] -1.7% impact from canceled and delayed projects including Halyard Wharton (419 MW), Halyard Henderson (450 MW), and Bacliff (324 MW); [2] -6.6% impact from announced retirements including Big Brown (1,208 MW), Monticello (1,865 MW), Sandow (1,200 MW), Barney Davis (330 MW), and Spencer (118 MW); [3] Weekly on-peak power prices

Financial Update

Financial Summary

($ millions)	September 30, 2017 Three Months Ended	September 30, 2017 Nine Months Ended	Updated Guidance *(prior guidance)* Full Year
Generation & Renewables[1,2]	$265	$545	$685 - $745 *($945 - $1,065)*
Retail	276	612	780 - 820 *(700 - 780)*
NRG Yield[2]	265	719	935 *(920)*
Adjusted EBITDA	**$806**	**$1,876**	**$2,400 – $2,500** *($2,565 - $2,765)*
Consolidated Free Cash Flow before Growth (FCFbG)	**$599**	**$807**	**$1,175 – $1,275** *($1,290 - $1,490)*
NRG-Level FCFbG	**$385**	**$514**	**$755 – $855** *($870 - $1,070)*

- Lowering 2017E financial guidance after trending to lower end of range at start of summer; incremental drivers include:
  - $65 MM due to mild summer weather and Hurricane Harvey impacts
  - $50 MM due to unfavorable results at BETM
- Reduced corporate debt by $604 MM in October resulting in incremental annual interest savings of $47 MM; nearest corporate maturity now 2022 – completing 2017 capital allocation plan
- Closed on sale of 38 MW portfolio of solar assets to NRG Yield for $71 MM[3] on November 1st increasing capital available for allocation, and formed new $50 MM solar partnership with NRG Yield

[1] Includes Corporate Segment; [2] In accordance with GAAP, restated to reflect impact of Utah Solar, 31% of NRG's interest in Agua Caliente drop down to NRG Yield, and remaining 25% in NRG Wind TE Holdco portfolio; [3] Excluding adjustment for working capital

Introducing 2018 Guidance

($ millions)	**2018 Guidance (including targeted divestitures)**	***Less: Full Year Impact of Divestitures[2]***	**2018 Pro Forma for Divestitures[3]**
Generation & Renewables[1]	$950 – $1,050	*($450)*	~$550
Retail	900 – 1,000	–	~950
NRG Yield	950	*(950)*	–
Adjusted EBITDA Guidance	**$2,800 - $3,000**	*($1,400)*	**~$1,500**
Consolidated Free Cash Flow before Growth ("FCFbG")	**$1,550 - $1,750**	*($670)*	**~$980**
Less: FCFbG at NRG Yield and Other Non-Guarantor Subsidiaries, net of distributions[4]	*(380)*	*(380)*	–
NRG-Level FCFbG	**$1,170 - $1,370**	*($290)*	**~$980**

	Includes	**Run rate (2020)**
Cost Savings	$500	$590
Margin Enhancement	$30	$215

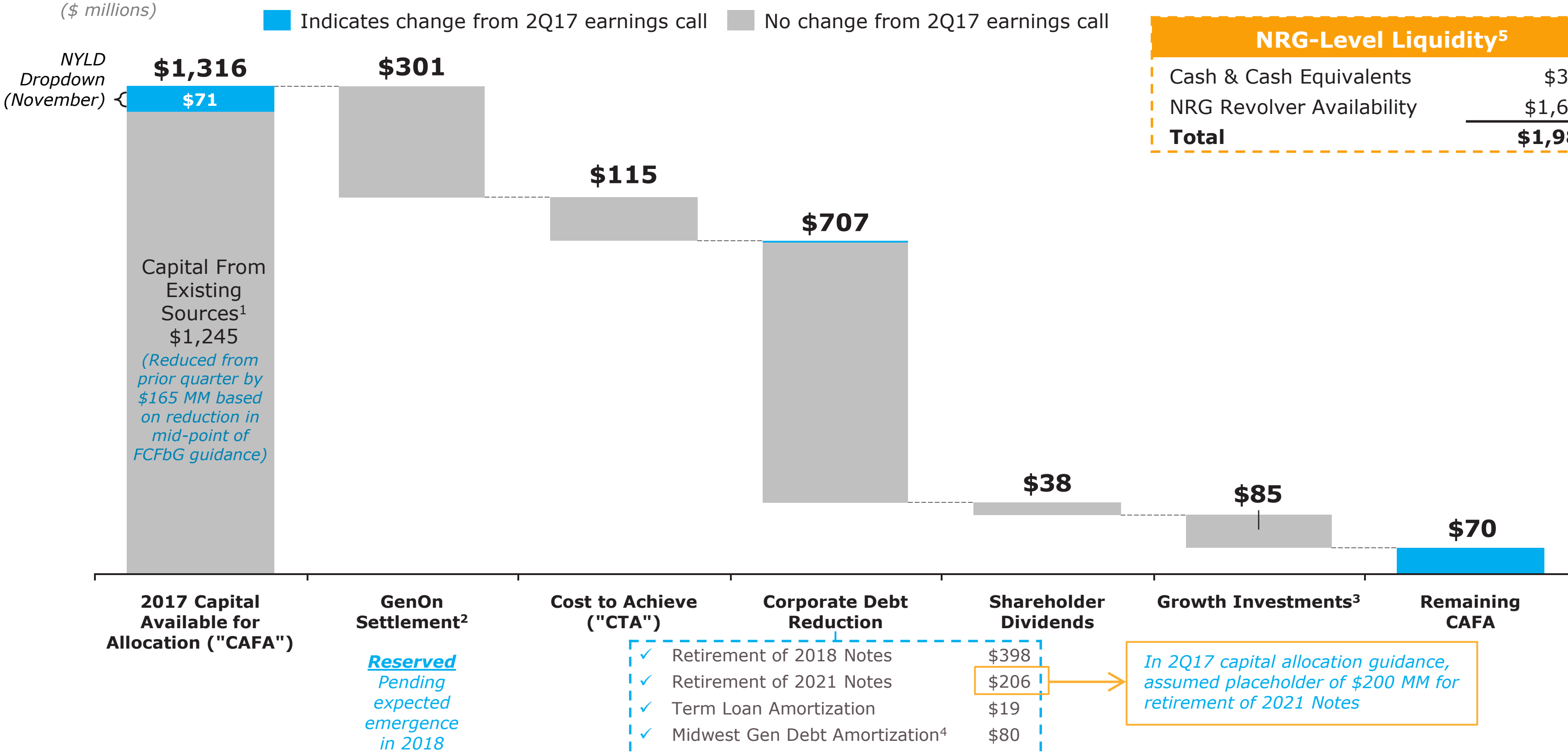
Guidance In-Line with Transformation Plan Targets

[1] Includes Corporate Segment; [2] Divestiture Adjusted EBITDA and FCFbG guidance represents 100% of NRG Yield and Renewables and ~6 GW of conventional generation and businesses per Transformation Plan announced on 7/12/2017; [3] Midpoint; assumes asset sales closed by 1/1/2018; [4] Represents FCFbG net of distributions to NRG Corp and to non-controlling interests; primarily Ivanpah, Agua Caliente, and Capistrano

2017 NRG-Level Capital Allocation

($ millions)

NRG-Level Liquidity[5]	
Cash & Cash Equivalents	$383
NRG Revolver Availability	$1,604
Total	**$1,987**



✓	Retirement of 2018 Notes	$398
✓	Retirement of 2021 Notes	$206
✓	Term Loan Amortization	$19
✓	Midwest Gen Debt Amortization[4]	$80
✓	Term Loan Refi Fees	$4

✓ = completed

In 2Q17 capital allocation guidance, assumed placeholder of $200 MM for retirement of 2021 Notes

Completed 2017 Debt Capital Allocation Plan With Retirement of 2018 and 2021 Senior Notes; GenOn Settlement Remains a Capital Allocation Reserve Until Emergence From Bankruptcy

[1] Refer to slide 19 of NRG 2Q17 earnings presentation. Capital from Existing Sources includes: 2016 YE cash & cash equivalents at NRG level of $570 MM less prior cash target of $500 MM (net of $71 MM in NRG Level cash collateral postings) plus midpoint of original NRG-level FCFbG guidance of $800 MM less $165 MM for reduction of midpoint of guidance plus $128 MM of Agua Caliente project-level net financing proceeds closed on 2/17/2017 and $130 MM of gross proceeds from drop down of Utah solar assets, 16% interest in Agua Caliente to NRG Yield closed on 3/27/2017, prior to working capital adjustments; plus NYLD dropdown completed in August 2017 of $41 MM; plus Cost Savings / Working Capital savings of $240 MM announced as part of the Transformation Plan; partially offset by $70 MM reduction in shared services; [2] $261.3 MM settlement plus $13 MM in pension funding plus $27 MM credit related to GenOn's 2022 Senior Notes issuance; [3] Net of financing; [4] Represents 2017 capacity revenue sold of $80 MM against $253 MM monetized in 2016; [5] Cash and cash equivalents of $998 MM as of 9/30/2017 less $615 MM of cash used to retire 2018 and 2021 Senior Notes in October 2017; includes $125 MM cash held at MWG which can be distributed to NRG Corporate with no restrictions; revolver availability represents $2.5 Bn revolving credit facility, less $0.9 Bn of letters of credit issued

NRG's Capital Structure & Corporate Credit Metrics

($ millions)

Debt and Cash Balances as of 9/30/2017

NRG Energy, Inc.[1]		
	Consolidated	**Recourse**
Total Debt:	$17,138	$7,796[2]
Total Cash:	$1,223	$998

Non-Recourse Debt

(Excluded Project Sub)

NRG Yield	ROFO/Renewables	Conventional
Total Debt: $5,901	Total Debt: $2,856	Total Debt: $587

~$9.3 Bn

	2017E	2018 Pro-Forma for Targeted Divestitures
Recourse Debt *(9/30/2017)*[2]	**$7,796**	**~$7,200**
2018/21 Debt Retirement	(604)	--
Term Loan Amortization	(5)	(20)
Additional Debt Reduction	--	(640)
Pro Forma Corporate Debt	**~$7,200**	**~$6,540**
Mid-Point Adj. EBITDA[3]	$2,450	$1,500
Less Adjusted EBITDA:		
NRG Yield	(935)	--
ROFO / Renewables / Conventional[4]	(315)	(125)
Add:		
NRG Yield Distributions to NRG[5]	90	--
ROFO / Other Dividends to NRG[6]	95	45
Other Adjustments[7]	150	150
Total Recourse EBITDA	**$1,535**	**$1,570**
Cash & Cash Equivalents @ NRG-Level[8]	$570	~$4,500
Corporate Net Debt/Corporate EBITDA	**4.3x**	**<3.0x**

Maintaining Balance Sheet Metrics In-Line With Targets

[1] Reflects deconsolidation of GenOn; [2] Includes NRG Energy Inc. term loan facility, senior notes, revolver, capital leases and tax exempt bonds; [3] 2017E includes $120 MM shared service payment from GenOn; [4] Includes Agua Caliente, Ivanpah, NRG Yield eligible assets, Capistrano, other renewable assets, and Midwest Generation (~$120MM in 2017 and ~$125MM in 2018); [5] Estimate based on NRG Yield dividends equivalent to $1.15/share by Q4 2017 and excludes impact of drop-down proceeds; [6] Includes MWG distributions of ~$60 MM in 2017 and ~$45 MM in 2018; [7] Reflects non-cash expenses (i.e. nuclear amortization, equity compensation amortization, and bad debt expense) that are included in Adjusted EBITDA; [8] 2017E composed of NRG-Level CAFA 2017 YE CAFA of $70 MM (see prior slide) plus $500 MM minimum cash; 2018E composed of minimum cash of $500 MM plus asset divestiture proceeds of $4.0 Bn

Closing Remarks

2017 Priorities

☑ **Updating 2017 Full Year Guidance Range to $2,400 MM - $2,500 MM Adjusted EBITDA**

❑ **Focus on Execution of the NRG Transformation Plan 2017 Objectives**

- ☑ Cost Savings and Margin Enhancements: $92 MM to date
- ❑ Portfolio Optimization: On track with vast majority of net cash proceeds expected to be announced in 2017, with balance in 2018
- ❑ Capital Structure and Allocation: Retired $604 MM of debt since 2Q17 earnings call

❑ **Finalize Comprehensive Resolution for GenOn**

- ☑ Filed Chapter 11 on 6/14/2017
- ❑ On path for plan confirmation on 11/13/2017 with finalized restructuring terms; emergence expected by 6/30/2018

❑ **Identify and Execute on Growth Opportunities with High Returns and Quick Capital Replenishment**

- ☑ Closed drop down in 1Q17 of Utah Solar Assets and 31% of NRG's interest Agua Caliente to NRG Yield
- ☑ Closed drop down in 2Q17 of remaining 25% interest in NRG Wind TE Holdco to NRG Yield
- ☑ Closed drop down of a 38 MW solar portfolio to NRG Yield, currently outside the ROFO pipeline
- ☑ Closed on new $50 MM distributed solar partnership with NRG Yield
- ❑ Offered 154 MW Buckthorn Solar asset to NRG Yield

☑ **Announcing NRG Investor Day for March 2018**

Q&A

Appendix: Transformation Plan Highlights

Please see NRG Investor Relations website for full 7/12/2017 Transformation Plan presentation

NRG Transformation Plan:
Process Background

The Business Review Committee ("BRC"), NRG management, and independent consultants/advisors conducted a 4-month, comprehensive evaluation across all NRG businesses, assets, and functions

The BRC review had three key focus areas: Operational and cost excellence initiatives, asset deconsolidations, dispositions and portfolio optimization, and capital structure and allocation

The BRC unanimously recommended a 3-part, 3-year transformation plan that was fully supported and approved by the NRG Board of Directors and NRG Management

The NRG transformation plan is front-loaded with realistic and achievable targets that can be implemented immediately

Transformation Plan Summary[1]

1 Achieve Cost Leadership and Enhance Earnings

- **$1,065 MM** in recurring cost and margin improvements: ~**70%** achieved by YE 2018 and over **90%** by YE 2019
  - Implement **$855 MM** recurring, annual free cash flow before growth (FCFbG) accretive cost reduction and margin enhancement program with 75+ levers identified to enhance value:
    - **$590 MM** cost savings; **$215MM** margin enhancement program; **$50 MM** maintenance capex reduction
  - Realize **$210 MM** permanent SG&A reduction associated with asset sales and divestments
- Achieve **$370 MM** working capital improvements and full plan's **$290 MM** one-time costs to achieve

2 Optimize Portfolio and Increase Focus on Integrated Platform

- Target net cash proceeds of **up to $4.0 Bn** from asset sales with vast majority of sales announcements anticipated by YE 2017, associated costs and debt reductions realized in 2018, and proceeds to be tax efficient given sizable NOL
- Divest **~21 GW** of conventional generation and businesses, including GenOn
- Anticipating **100%** sale of NRG's interest in NRG Yield and Renewables to deconsolidate and simplify NRG structure while maintaining ability to provide comprehensive energy solutions

3 Focus on Disciplined Capital Allocation, priorities:

- First: Achieve and maintain **top decile safety** and operational excellence
- Second: Reduce net debt/adjusted EBITDA to **3.0x** by YE 2018
- Third: Selectively invest in compelling projects with less than **5 year payback** period and stringent unlevered pre-tax return of at least **12% - 15%**
- Fourth: Allocate to **shareholder return programs** once capital structure objectives have been met and high capital return investments have been funded

4 Strong Governance Focused on Transformation Plan Achievement

- Oversight by full Board of Directors with monthly updates to the Board's Finance and Risk Management Committee and quarterly scorecard to investors
- Newly created dedicated implementation team
- Existing management compensation aligned to Transformation Plan execution and success

[1] As announced July 12, 2017 and updated on November 2, 2017; post asset divestitures

Transformation Plan Score Card

Progress as of 9/30/2017

($ millions)	YTD Realized	% achieved	2017 Target
Accretive & Recurring:			
Cost Savings	92	142%	65
Margin Enhancement*	-	-	0
Total EBITDA - Accretion	**92**	**142%**	**$65**
Maintenance Capex*	-	-	0
Total Recurring FCFbG - Accretion	**$92**	**142%**	**$65**
Non-Recurring:			
Working Capital Improvement	89	51%	175
Cost to Achieve Total Transformation Plan	(20)	17%	(115)
Total Non-Recurring	**$69**	**-**	**$60**
Annual Cash Accretion	**$161**	**129%**	**$125**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$161**	**129%**	**$125**

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

Transformation Plan Target[1]

($ millions)	2017	2018	2019	2020 / Run Rate
Accretive & Recurring:				
Cost Savings	65	500	590	590
Margin Enhancement	0	30	135	215
Total EBITDA - Accretion	**$65**	**$530**	**$725**	**$805**
Maintenance Capex	0	30	50	50
Total Recurring FCFbG Accretion	**$65**	**$560**	**$775**	**$855**
Non-Recurring:				
Working Capital Improvement	175	85	110	--
Cost to Achieve Total Transformation Plan	(115)	(175)	--	--
Total Non-Recurring	**$60**	**($90)**	**$110**	**--**
Annual Cash Accretion	**$125**	**$470**	**$885**	**$855**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$125**	**$595**	**$1,480**	**$2,335**

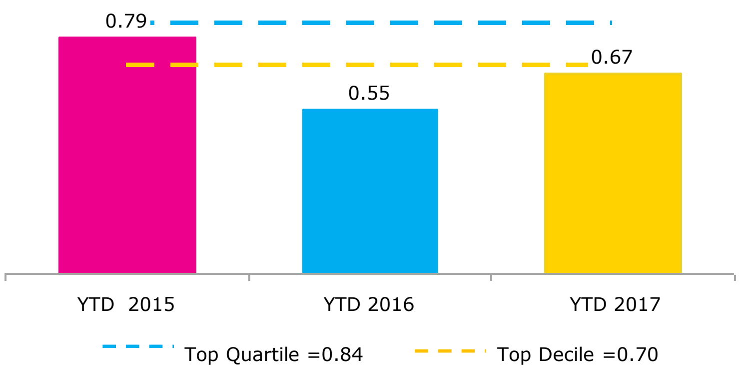
[1] Post asset divestitures

Appendix: Operations

Generation/Business: Operational Metrics

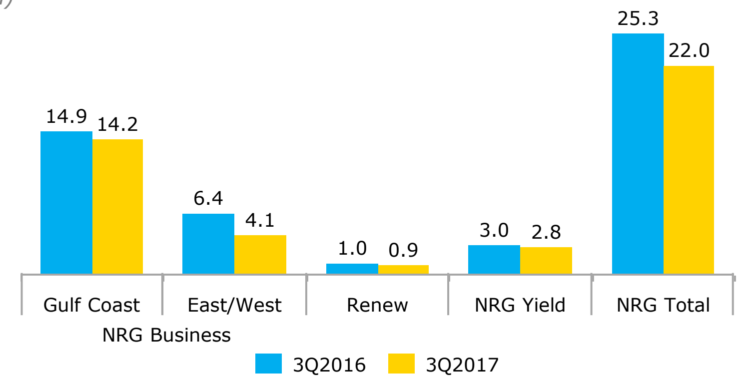
Safety[1]

(TCIR)[2]



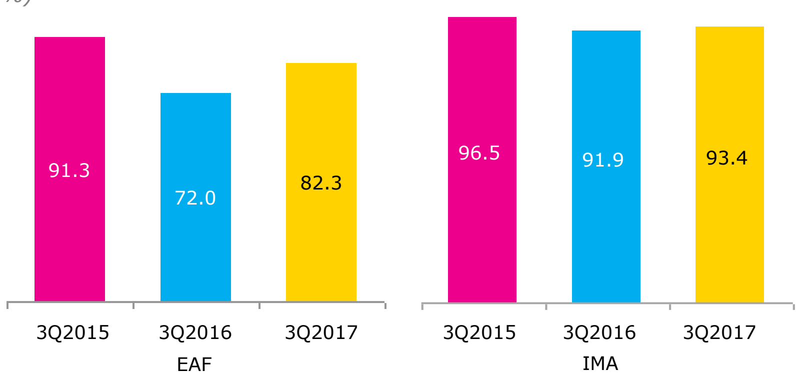
Production

(TWh)[3]



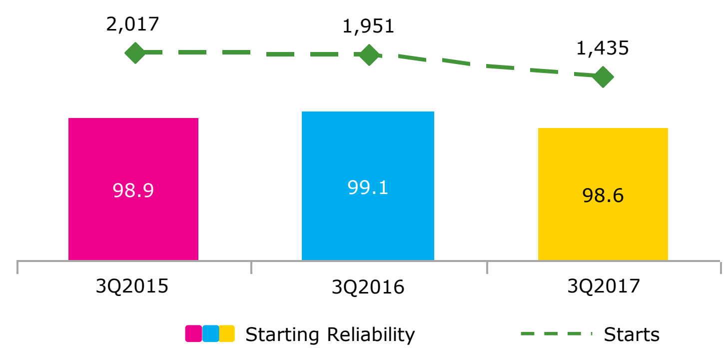
Baseload EAF and In the Money Availability

(%)



Gas and Oil Starts and Reliability

(%)



Top Decile Safety Results and Strong In the Money Availability

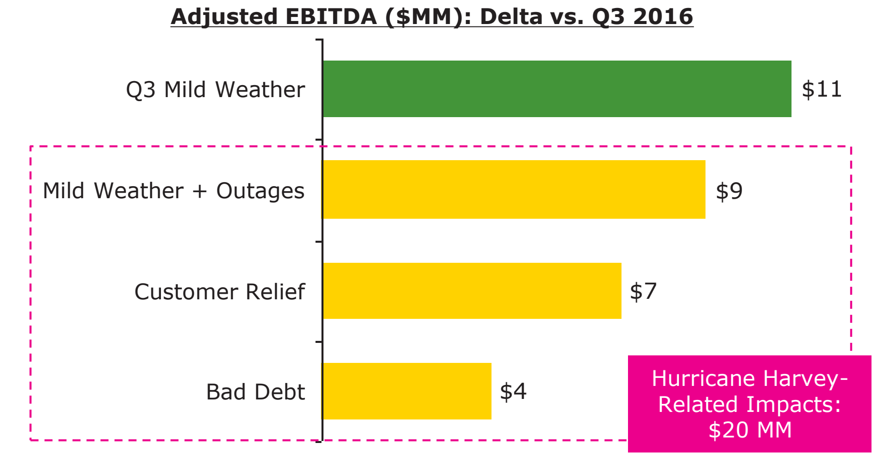
[1] Excludes Goal Zero, NRG Home Services and NRG Home Solar; top decile and top quartile based on Edison Electric Institute 2015 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation; excludes line losses, station service, and other items. Generation data presented above consistent with US GAAP accounting. Previous reports were pro-forma for acquisitions in prior periods

Retail: Operational Metrics

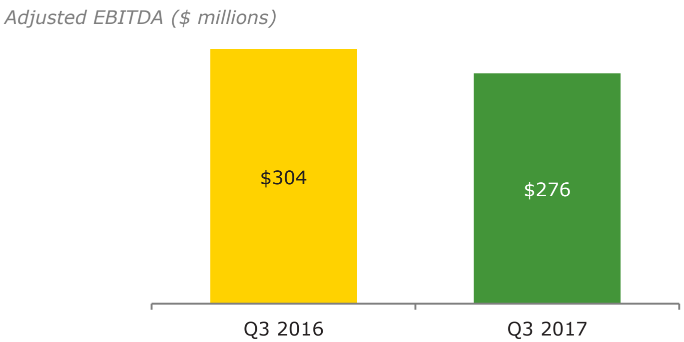
3rd Quarter Highlights

- Delivered $276 MM in Q3 Adjusted EBITDA, lower than last year but strong results given weather and Harvey impacts
- Continued customer momentum with 84k (3%) net mass customer growth versus 3Q16 (over the past year)
- Advanced cost savings both as part of the transformation program and those completed earlier in the year that are now delivering in 3Q/expected in 4Q
- Increased 2017E Retail financial guidance to $780-820 MM from $700-800 MM Adjusted EBITDA

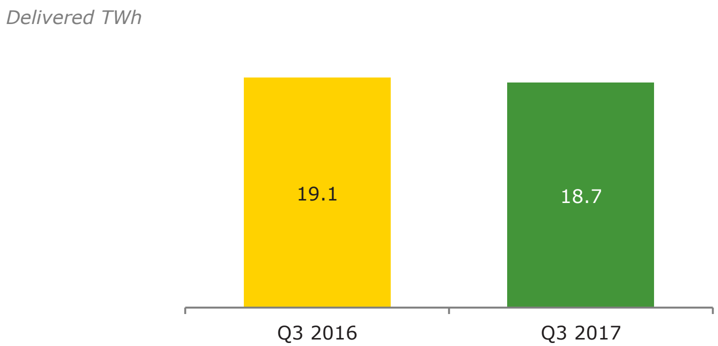
Weather / Hurricane Impacts During Q3



Q3 EBITDA Earnings



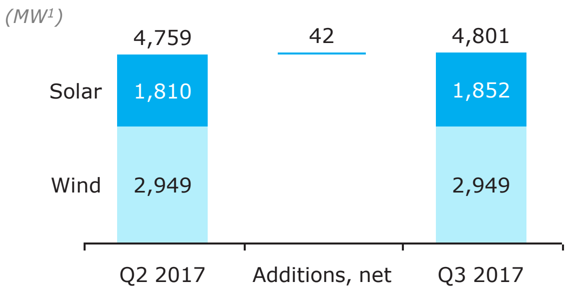
Q3 Volumes

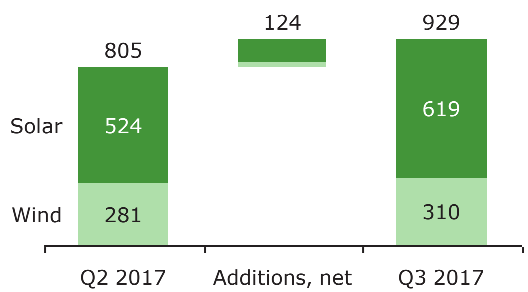


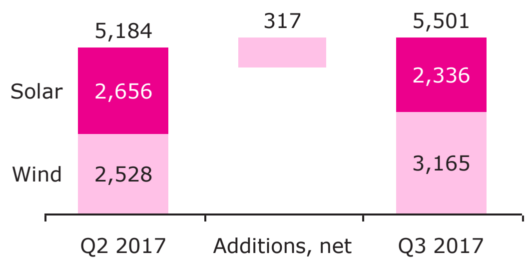
Raising Retail Guidance Given Strong Operating Performance and Efficiencies

Renewables: Portfolio Update

Quarter over Quarter Change







Key Q3 Updates

Operating Portfolio: 4,801 MW[1,2]

- ☑ 42 MW converted from backlog reflects DG and community solar additions across CA, ME, and MN
- ☑ Completed sale of 38 MW solar assets portfolio to NRG Yield

2017-2019 Backlog: 929 MW[3]

- ☑ 116 MW converted from pipeline (124 MW net of conversion to operating) reflects solar and wind additions in CA and ERCOT
- ☑ Offered NRG Yield 100% purchase of Buckthorn Solar (154 MW) scheduled for COD in 1H18
- ☑ Expanded Community Solar portfolio in NY with additional 21 MW under contract
- ☑ 322 MW in construction across utility-scale wind and solar, Community and DG

Utility–Scale and DG Pipeline: 5,501 MW[4]

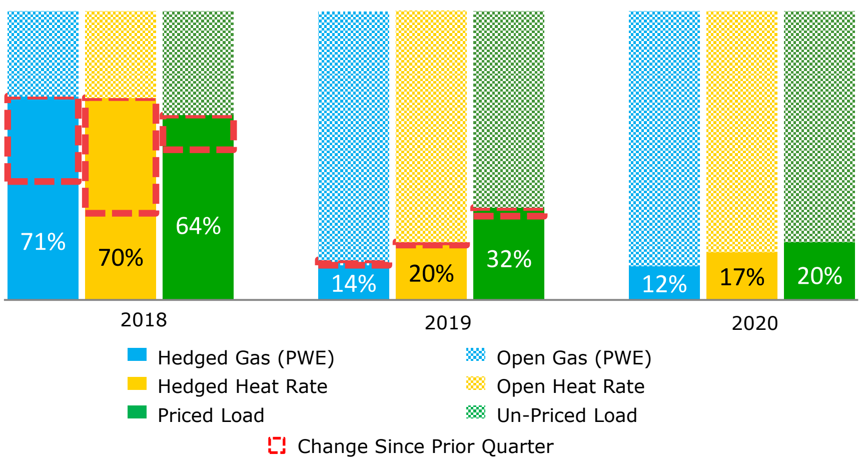
- ☑ 483 MW (317 MW net of conversion to backlog) increase reflects utility scale origination in ERCOT, MISO, and CAISO
- ☑ Acquired 276 MW wind project in ERCOT, progressing late-stage offtake negotiation
- ☑ Expanded Community Solar project site pipeline across MA, MN, and NY
- ☑ Grew DG project pipeline with clients in C&I and municipal segments

Significant Scale and with a Substantial Pipeline for Future Growth

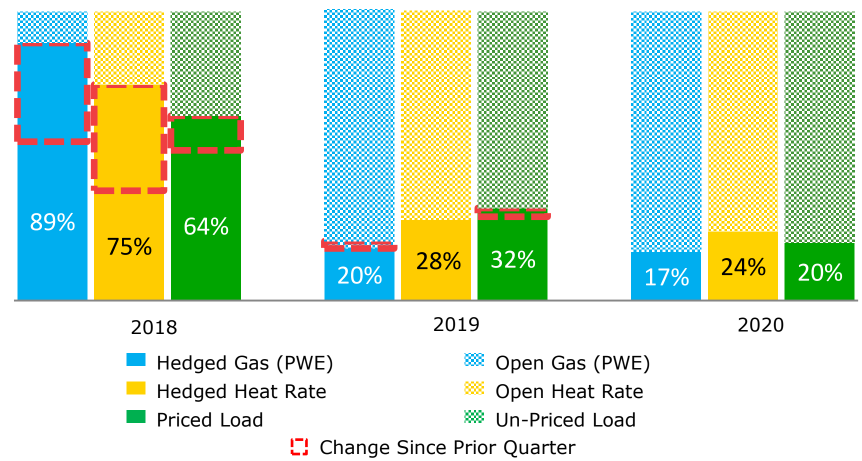
[1] 4.8 GW at NRG Consolidated, of which 3.1 GW is at NRG Yield; [2] MW amounts in AC; [3] Backlog is defined as projects that are under construction, contracted, or awarded, and represents a higher level of execution certainty; [4] Pipeline is defined as projects that range from identified lead to shortlisted with an offtake and represents a lower level of execution certainty

Managing Commodity Price Risk

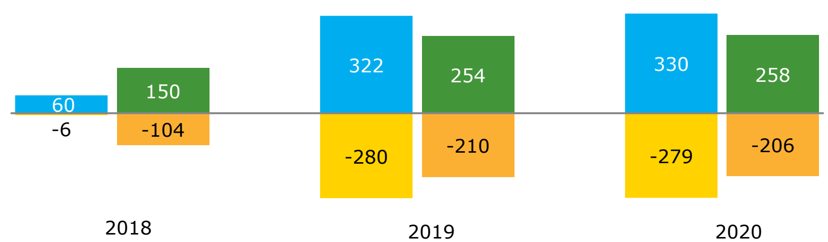
Total Portfolio Generation and Retail Hedge Position[1,2,5]



Coal and Nuclear Generation and Retail Hedge Position[1,2,4]



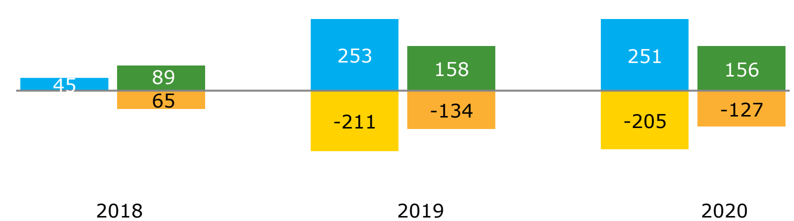
Total Portfolio Sensitivity to Gas Price and Heat Rate[1,3,5]



	2018	2019	2020
Henry Hub Gas as of 10/26	3.04	2.91	2.86

Gas Up By $0.5/mmBtu
Gas Down By $0.5/mmBtu
HR Up By 1 mmBtu/MWh
HR Down By 1 mmBtu/MWh

Coal and Nuclear Generation Sensitivity to Gas Price and Heat Rate[1,3]



	2018	2019	2020
Henry Hub Gas as of 10/26	3.04	2.91	2.86

Gas Up By $0.5/mmBtu
Gas Down By $0.5/mmBtu
HR Up By 1 mmBtu/MWh
HR Down By 1 mmBtu/MWh

[1] Portfolio as of 10/26/2017; [2] Retail priced load includes term load, Hedged month-to-month load, and Indexed load; [3] Price sensitivity reflects gross margin change from $0.5/MMBtu gas price, 1 mmBtu/MWh heat rate move; [4] Coal hedge ratios are 71%, 26%, and 23% for 2018, 2019, and 2020, respectively; [5] Total Portfolio includes wholesale merchant assets and related hedges

Hedge Disclosure: Coal and Nuclear Operations

Coal & Nuclear Portfolio[1]		Texas and South Central			EAST		
		2018	2019	2020	2018	2019	2020
	Net Coal and Nuclear Capacity (MW)[2]	6,250	6,250	6,250	3,267	3,267	3,267
	Forecasted Coal and Nuclear Capacity (MW)[3]	4,558	4,387	4,269	1,507	1,330	1,099
	Total Coal and Nuclear Sales (GWh)[4]	34,194	8,295	7,312	13,218	1,474	603
	Percentage Coal and Nuclear Capacity Sold Forward[5]	86%	22%	19%	100%	13%	6%
	Total Forward Hedged Revenues [6]	$1,417	$431	$402	$427	$45	$18
	Weighted Average Hedged Price ($ per MWh)[6]	$41.45	$51.95	$55.05	$32.34	$30.37	$30.38
	Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$3.41	$4.70	$4.94	$3.06	$2.97	$2.82
Gross Margin Sensitivities $ in MM	Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	$9	$146	$145	$36	$107	$106
	Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$31	($127)	($128)	($23)	($84)	($77)
	Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$62	$94	$96	$27	$64	$60
	Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	($43)	($79)	($77)	($22)	($55)	($50)

[1] Portfolio as of 10/26/2017; [2] Net Coal and Nuclear capacity represents nominal summer net MW capacity of power generated as adjusted for the Company's ownership position excluding capacity from inactive/mothballed units; [3] Forecasted generation dispatch output (MWh) based on forward price curves as of 10/26/2017 which is then divided by number of hours in a given year to arrive at MW capacity; the dispatch takes into account planned and unplanned outage assumptions; [4] Includes amounts under power sales contracts and natural gas hedges; the forward natural gas quantities are reflected in equivalent GWh based on forward market implied heat rate as of 10/26/2017 and then combined with power sales to arrive at equivalent GWh hedged; the Coal and Nuclear Sales include swaps and delta of options sold which is subject to change; 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 2016 10K Item 15 - Note 5, Accounting for Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements; includes inter-segment sales from the Company's wholesale power generation business to the Retail Business; [5] Percentage hedged is based on Total Coal and Nuclear sales as described above ([4]) divided by the forecasted Coal and Nuclear Capacity ([3]); [6] Represents all coal and nuclear sales, including energy revenue and demand charges

Commodity Prices

Forward Prices[1]	2018	2019	2020	Annual Average for 2018-2020
NG Henry Hub	$3.04	$2.91	$2.86	$2.94
PRB 8800	$12.16	$12.20	$12.25	$12.20
ERCOT Houston Onpeak	$39.10	$37.32	$36.40	$37.61
ERCOT Houston Offpeak	$23.02	$22.28	$21.93	$22.41
PJM West Onpeak	$36.80	$34.84	$33.75	$35.13
PJM West Offpeak	$26.30	$25.40	$24.80	$25.50

[1] Prices as of 10/26/2017

Fuel Statistics

	3Q		YTD	
Domestic[1]	**2017**	**2016**	**2017**	**2016**
Coal Consumed (mm Tons)	6.7	7.8	18.0	17.7
PRB Blend	**92%**	**85%**	**93%**	**84%**
East	94%	95%	97%	96%
Gulf Coast	92%	81%	92%	79%
Bituminous	**1%**	**2%**	**1%**	**1%**
East	6%	5%	3%	4%
Lignite	**7%**	**13%**	**6%**	**15%**
Gulf Coast	8%	19%	8%	21%
Cost of Coal ($/Ton)	**$ 32.34**	**$ 31.29**	**$ 32.33**	**$ 32.35**
Cost of Coal ($/mmBtu)	**$ 1.90**	**$ 1.88**	**$ 1.90**	**$ 1.95**
Cost of Gas ($/mmBtu)	**$ 3.02**	**$ 2.79**	**$ 3.10**	**$ 2.43**

[1] NRG's interests in Keystone and Conemaugh (jointly owned plants) are excluded from the fuel statistics schedule

Q3 2017 Generation & Operational Performance Metrics

(MWh 000's)	2017 Generation[1]	2016 Generation[1]	MWh Change	% Change	2017 EAF[2]	2017 NCF[3]	2016 EAF[2]	2016 NCF[3]
Gulf Coast – Texas	11,490	12,512	(1,021)	(8%)	93%	48%	89%	52%
Gulf Coast – South Central	2,696	2,415	281	12%	95%	31%	90%	30%
East/West	4,106	6,426	(2,320)	(36%)	90%	15%	88%	39%
Renewables	928	978	(50)	(5%)	96%	33%	96%	33%
NRG Yield[4]	2,768	2,994	(225)	(8%)	98%	23%	98%	25%
Total	**21,988**	**25,324**	**(3,336)**	**(13%)**	**93%**	**30%**	**90%**	**40%**
Gulf Coast – Texas Nuclear	2,516	2,513	3	0%	100%	97%	100%	97%
Gulf Coast – Texas Coal	7,161	7,081	80	1%	90%	77%	88%	76%
Gulf Coast – South Central Coal	1,342	1,382	(40)	(3%)	93%	41%	81%	42%
East Coal	2,400	4,428	(2,028)	(46%)	82%	24%	81%	44%
Baseload	**13,419**	**15,405**	**(1,986)**	**(13%)**	**88%**	**53%**	**85%**	**61%**
Renewables Solar	529	518	11	2%	99%	54%	100%	55%
Renewables Wind	399	460	(61)	(13%)	95%	27%	96%	28%
NRG Yield Solar	357	380	(23)	(6%)	99%	35%	100%	38%
NRG Yield Wind	1,187	1,364	(177)	(13%)	96%	26%	98%	30%
Intermittent	**2,472**	**2,722**	**(250)**	**(9%)**	**96%**	**28%**	**97%**	**32%**
East Oil	32	40	(8)	(19%)	92%	0%	92%	56%
Gulf Coast – Texas Gas	1,813	2,917	(1,104)	(38%)	93%	16%	90%	25%
Gulf Coast – South Central Gas	1,354	1,033	321	31%	97%	26%	95%	24%
East Gas	458	767	(309)	(40%)	94%	9%	89%	19%
West Gas	1,215	1,191	24	2%	99%	30%	97%	28%
NRG Yield Conventional	717	629	89	14%	99%	17%	97%	15%
NRG Yield Thermal[4]	507	621	(114)	(18%)	100%	14%	98%	46%
Intermediate / Peaking	**6,097**	**7,198**	**(1,101)**	**(15%)**	**95%**	**15%**	**92%**	**29%**

[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor; [4] Includes MWh (thermal heating & chilled water generation); NCF not inclusive of MWht

YTD 2017 Generation & Operational Performance Metrics

(MWh 000's)	2017 Generation[1]	2016 Generation[1]	MWh Change	% Change	2017 EAF[2]	2017 NCF[3]	2016 EAF[2]	2016 NCF[3]
Gulf Coast – Texas	29,300	29,310	(10)	(0%)	88%	42%	90%	42%
Gulf Coast – South Central	8,676	7,117	1,558	22%	90%	34%	88%	34%
East/West	10,202	13,732	(3,530)	(26%)	86%	21%	78%	25%
Renewables	2,940	2,968	(28)	(1%)	96%	37%	97%	37%
NRG Yield[4]	7,997	8,573	(576)	(7%)	95%	23%	96%	23%
Total	**59,115**	**61,701**	**(2,586)**	**(4%)**	**89%**	**30%**	**86%**	**32%**
Gulf Coast – Texas Nuclear	6,934	7,468	(534)	(7%)	92%	90%	99%	97%
Gulf Coast – Texas Coal	18,649	16,180	2,469	15%	91%	68%	87%	59%
Gulf Coast – South Central Coal	3,679	4,247	(568)	(13%)	86%	38%	82%	43%
East Coal	6,964	9,578	(2,615)	(27%)	84%	23%	64%	31%
Baseload	**36,226**	**37,473**	**(1,247)**	**(3%)**	**87%**	**48%**	**78%**	**50%**
Renewables Solar	1,405	1,330	76	6%	99%	45%	100%	54%
Renewables Wind	1,535	1,639	(104)	(6%)	96%	35%	96%	33%
NRG Yield Solar	949	1,012	(63)	(6%)	99%	32%	100%	34%
NRG Yield Wind	4,345	4,551	(205)	(5%)	97%	32%	98%	34%
Intermittent	**8,235**	**8,531**	**(296)**	**(3%)**	**97%**	**33%**	**98%**	**35%**
East Oil	76	73	3	5%	87%	35%	91%	32%
Gulf Coast – Texas Gas	3,717	5,662	(1,945)	(34%)	85%	11%	91%	16%
Gulf Coast – South Central Gas	4,996	2,870	2,126	74%	92%	32%	91%	29%
East Gas	894	1,260	(366)	(29%)	87%	6%	80%	11%
West Gas	2,268	2,821	(553)	(20%)	90%	19%	91%	23%
NRG Yield Conventional	1,172	1,265	(93)	(7%)	92%	9%	94%	10%
NRG Yield Thermal[4]	1,530	1,745	(215)	(12%)	96%	7%	93%	29%
Intermediate / Peaking	**14,654**	**15,696**	**(1,042)**	**(7%)**	**88%**	**18%**	**89%**	**20%**

[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor; [4] Includes MWh (thermal heating & chilled water generation); NCF not inclusive of MWht

In the Money Availability Calculation

"In the Money Availability" (IMA) is an NRG performance measurement leveraging Generating Availability Data System (GADS) data and market prices to calculate the percentage of generation available during periods when market prices allow these units to be dispatched profitably.

- Transitioning from Equivalent Availability Factor (EAF) to IMA allows us to measure our availability during the greatest opportunities to capture value. IMA performance measurement bridges operational performance to shareholder value.
- IMA uses similar approach as GADS EAF calculation:

$$\textbf{EAF} = \frac{\textbf{(Avail Hours – All Eq. Unplanned Outage Hrs)}}{\textbf{Period Hours}} \times 100$$

$$\textbf{IMA} = \frac{\textbf{(IMA Avail Hours - IMA Eq. Lost Margin Hrs)}}{\textbf{IMA Avail Hours}} \times 100$$

- Factors that impact IMA include forced outages, derates, maintenance, and/or extensions to planned and unplanned outages, when a unit is in the money; reserve shutdown hours (SH) are not included
- IMA "Available Hours" equals period hours less planned outage hours and uneconomic hours when an unplanned curtailing event occurs
- IMA "Equivalent Lost Margin Hours" (ELMH) are calculated similarly Equivalent Unplanned Outage Hours (EUOH) used for EAF
  - If there is lost margin during the hour of the curtailing event, the hour is be included as both an IMA Available Hour and an IMA ELMH
  - If there is zero lost margin during the hour of the curtailing event, the hour is not included in the available hour count and the ELMH would be zero for that hour

PJM Capacity Clears: NRG Standalone

PJM Region	Planning Year	Base Product: Average Price ($/MW-day)[1]	Base Product: MWs Cleared	Capacity Performance Product: Average Price ($/MW-day)[1]	Capacity Performance Product: MWs Cleared
ComEd	2017-2018	$145.51	539	$151.50	3,227
	2018-2019	$25.36	225	$215.00	3,509
	2019-2020	$182.77	65	$202.77	3,738
	2020-2021			$188.12	3,315
MAAC	2017-2018	$116.96	17	$151.50	106
	2018-2019	$149.98	1	$164.77	108
	2019-2020	$80.00	1	$100.00	105
	2020-2021			$86.04	91
EMAAC	2017-2018	NA	NA	NA	NA
	2018-2019	NA	NA	NA	NA
	2019-2020	NA	NA	NA	NA
	2020-2021			NA	NA
DPL South	2017-2018	$150.03	133	$151.50	358
	2018-2019	$210.63	98	$225.42	459
	2019-2020	NA	NA	$119.77	481
	2020-2021			$187.87	519
PEPCO	2017-2018	$111.13	80	NA	NA
	2018-2019	NA	NA	$164.77	69
	2019-2020	NA	NA	$100.00	66
	2020-2021			$86.04	67
ATSI	2017-2018	NA	NA	NA	NA
	2018-2019	NA	NA	NA	NA
	2019-2020	NA	NA	NA	NA
	2020-2021			NA	NA
RTO	2017-2018	$126.13	907	$151.50	9
	2018-2019	NA	NA	NA	NA
	2019-2020	NA	NA	NA	NA
	2020-2021			NA	NA
Net Total	2017-2018	$133.46	1,676	$151.50	3,701
	2018-2019	$81.75	324	$227.69	4,144
	2019-2020	$181.51	65	$189.69	4,389
	2020-2021			$184.04	3,992

PJM Capacity Revenue by Delivery Year

($ MM)	NRG
17/18	$286
18/19	$354
19/20	$309
20/21	$268

PJM Capacity Revenue by Calendar Year

($ MM)	NRG
2017	$247
2018	$326
2019	$327
2020	$286

Assumptions:

- Data as of 5/23/2017
- Includes imports
- Excludes NRG Yield Assets
- Represents merchant wholesale generation

[1] Average Price ($/MW-day) can vary from stated BRA cleared auction price due to MWs purchased or sold in incremental auctions

PJM Asset List: Merchant Wholesale Generation

Net Generating Capacity by LDA

COMED (4,336 MW)

Name	Location	Capacity	Entity	Ownership %
Fisk	Chicago, IL	172	NRG	100.0%
Joliet	Joliet, IL	1,326	NRG	100.0%
Powerton	Pekin, IL	1,538	NRG	100.0%
Waukegan	Waukegan, IL	790	NRG	100.0%
Will County	Romeoville, IL	510	NRG	100.0%

DPL (593 MW)

Name	Location	Capacity	Entity	Ownership %
Indian River	Millsboro, DE	426	NRG	100.0%
Vienna	Vienna, MD	167	NRG	100.0%

MAAC (126 MW)

Name	Location	Capacity	Entity	Ownership %
Conemaugh	New Florence, PA	63	NRG	3.72%
Keystone	Shelocta, PA	63	NRG	3.70%

PEPCO (78 MW)

Name	Location	Capacity	Entity	Ownership %
SMECO	Prince Georges County, MD	78	NRG	100.0%

Assumptions:

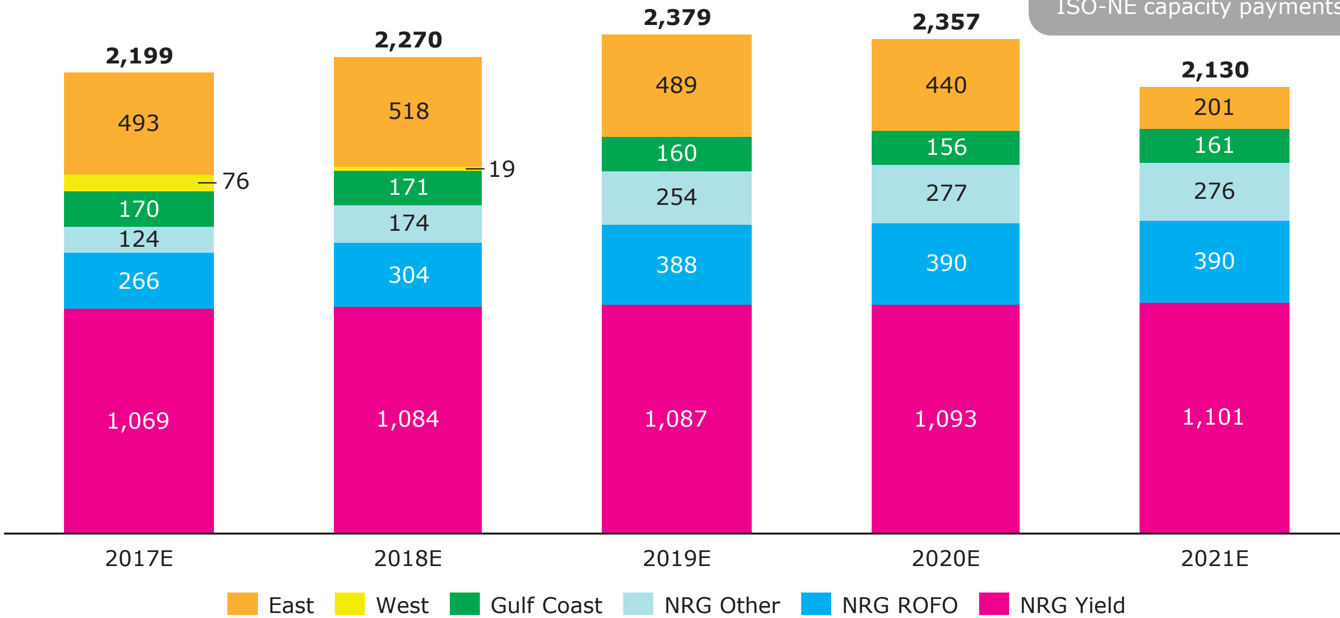
- Data reflects physical location of generating unit; reflects demonstrated summer capacity with NRG's ownership applied, including conversions
- Excludes NYLD assets Dover 104 MW in DPL and Paxton Creek 12 MW in MAAC
- Data as of 6/30/2017

Appendix: Finance

Fixed Contracted and Capacity Revenue (3Q17)

($ millions)

Excludes Penalties and Uncleared:
NYISO capacity payments (post 2018)
PJM capacity payments (post 20/21 BRA)
ISO-NE capacity payments (post 20/21 FCA11)



Notes:

- East includes cleared capacity auction for PJM through May 2021, New England ISO Forward Capacity Auction 11 (FCA11) through May 2021; NY on rolling forward basis
- West includes committed Resource Adequacy contracts & tolling agreements
- Gulf Coast region includes South Central capacity sold into PJM/MISO auctions and Co-Op contracted revenues. Co-Op contracted revenues are also incorporated in the hedge table
- NRG ROFO includes all wind, solar and conventional assets which are part of ROFO agreement including projects under construction (Carlsbad)
- NRG Other includes renewable assets which are not part of ROFO and preferred resources projects
- NRG Yield includes contracted capacity, contracted energy and contracted steam revenues

YTD 3Q17 Net Capital Expenditures

($ millions)	Maintenance	Environmental	Growth	Total
Generation				
Gulf Coast[1]	$73	$1	$3	$77
East/West[2]	17	24	240	281
Retail	22	-	33	55
Renewables	3	-	309	312
NRG Yield	21	-	2	23
Corporate	11	-	1	12
Total Cash Capital Expenditures	**$147**	**$25**	**$588**	**$760**
Other Investments[3]	-	-	95	95
Project Funding, net of fees[4]	-	-	(815)	(815)
Total Capital Expenditures and Growth Investments, net	**$147**	**$25**	**($132)**	**$40**

[1] Excludes $22 MM of insurance proceeds on maintenance capex; [2] Also includes International and BETM. Includes growth capital spend related to Carlsbad; [3] Includes investments and acquisitions; [4] Includes net debt proceeds, cash grants and third-party contributions

Growth Investments and Capex, Net of Financing

($ millions)	2017E	2018E[1]
NRG Level		
Growth	85	155
Environmental	35	5
Maintenance	188	155
Other[2]		
Growth	2	-
Environmental	-	-
Maintenance	35	-

[1] Pro forma for asset divestitures and cost reductions per Transformation Call on 7/12/2017; [2] Other includes NRG Yield, Ivanpah, and Agua Caliente (excluded from 2018 estimate assuming divestitures close on 1/1/2018)

Generation Organizational Structure

NRG Energy, Inc. (30,121[1] MW)

Renewables (976 MW)

Solar
- Agua Caliente[2]
- Blythe II
- Community Solar
- Distributed Solar
- Guam
- Ivanpah
- Spanish Town
- Stadiums

Wind
- Bingham Lake
- Broken Bow
- Cedro Hill
- Community Wind
- Crofton Bluffs
- Eastridge
- Jeffers
- Langford
- Mountain Wind I&II
- Sherbino

NRG Yield (2,867 MW)

- Alta Wind
- Alpine
- Avenal
- Avra Valley
- Blythe
- Borrego
- Buffalo Bear
- Crosswinds
- CVSR
- Desert Sunlight
- Distributed Solar
- Dover
- El Segundo
- Elbow Creek
- Elkhorn Ridge
- Forward
- GenConn Devon
- GenConn Middletown
- Goat Wind
- Hardin
- High Desert
- Kansas South
- Laredo Ridge
- Lookout
- Marsh Landing
- Odin
- Paxton Creek
- Pinnacle
- Princeton
- Roadrunner
- San Juan Mesa
- South Trent
- Spanish Fork
- Spring Canyon II & III
- Sleeping Bear
- Taloga
- Tucson
- Univ. of Bridgeport
- Walnut Creek
- Wildorado

Gulf Coast (13,692 MW)

Texas (10,508 MW)
- Cedar Bayou
- Cedar Bayou 4
- Greens Bayou
- Gregory
- Limestone
- San Jacinto
- South Texas Project
- TH Wharton
- WA Parish

South Central (3,555 MW)
- Bayou Cove
- Big Cajun I
- Big Cajun II
- Cottonwood
- Sterlington

Other Conventional (22 MW)

- Petra Nova Cogen

West (2,129 MW)

- Encina
- Long Beach
- Midway Sunset
- Saguaro
- San Diego Jet
- Sunrise
- Watson

Residential Solar (114 MW)

Other (749 MW)

- Doga
- Gladstone

East (9,572 MW)

- Arthur Kill
- Astoria
- Conemaugh
- Connecticut Jets
- Devon
- Fisk
- Indian River
- Joliet
- Keystone
- Middletown
- Montville
- Oswego
- Powerton
- SMECO
- Vienna
- Waukegan
- Will County

Drop down to NRG Yield on March 27, 2017:
- Agua Caliente[2]
- Four Brothers[3]
- Granite Mountain[3]
- Iron Springs[3]

LEGEND

Separate Credit Facility

drop down to NRG Yield on March 27, 2017

Equity Investments

[1] Capacity controlled by NRG as of 9/30/2017, excluding GenOn; [2] Agua Caliente is 51% owned by NRG Consolidated, of which 16% is owned by NRG Yield; [3] Four Brothers, Granite Mountain, and Iron Springs are 50% owned by NRG Yield

Consolidated Debt Structure
as of 9/30/2017

($ millions)

LEGEND
- Recourse Debt
- Non-Recourse Debt
- SEC Filer

NRG Energy, Inc.

Revolver $2.5 BN due 2018/2021[1]	$ 0
Senior notes due 2018-2027	5,449
Term loan due 2023	1,876
Tax exempt bonds due 2038-2045	465
Capital Lease	6
Total	**$ 7,796**

Conventional Financings

Other non-recourse debt	$ 7

Midwest Generation

Capacity Monetization/ Operating leases[2]	$ 173

Carlsbad Energy

Term Loan	$ 407

Agua Caliente

Project financing due 2037	$ 833
Borrower 1 due 2038	89

Ivanpah

Promissory Note and Project financing due 2033 and 2038	$ 1,163

Other Renewables Financings

Project financings	$ 769

NRG Yield, Inc.

Senior convertible notes due 2019-2020	$ 633

NRG Yield Operating LLC

Revolver $495 MM due 2019[3]	$ 0
Green Bond notes	500
Senior Notes Due 2026	350

Conventional

Term loans due 2017 & 2023	$ 1,058

Thermal

Senior secured notes due 2017-2025 and 2031	$ 207

Renewable

Project financings[4]	$ 3,153

Note: Debt balances exclude discounts and premiums
[1] $932 MM LC's issued and $1,604 MM Revolver available at NRG; [2] The present value of lease payments (9.1% discount rate) for Midwest Generation operating lease is $93 MM; this lease is guaranteed by NRG Energy, Inc.; [3] $68 MM of LC's were issued and $427 MM of the Revolver was available at NRG Yield; [4] Includes Four Brothers Holdings, Iron Springs Renewables, and Granite Mountain Renewables following the drop down on 3/27/2017

Recourse / Non-Recourse Debt

($ millions)	9/30/2017	6/30/2017	3/31/2017	12/31/2016
Recourse Debt				
Term Loan Facility	$ 1,876	$ 1,881	$ 1,886	$ 1,891
Senior Notes	5,449	5,449	5,449	5,449
Tax Exempt Bonds	465	455	455	455
Revolver	-	-	125	-
Capital Lease	6	6	8	-
Recourse Debt Subtotal	**$ 7,796**	**$ 7,791**	**$ 7,923**	**$ 7,795**
Non-Recourse Debt				
Total NRG Yield[1,2]	$ 5,901	$ 5,983	$ 6,051	$ 6,085
Renewables (including capital leases)[2]	2,854	2,811	2,661	2,592
Conventional	587	546	220	238
Non-Recourse Debt and Capital Lease Subtotal	**$ 9,342**	**$ 9,340**	**$ 8,932**	**$ 8,915**
Total Debt	**$ 17,138**	**$ 17,131**	**$ 16,855**	**$ 16,710**

Note: Debt balances exclude discounts and premiums
[1] Includes convertible notes and project financings; [2] NRG Yield has been recast following the CVSR drop down on 9/01/2016 and the Four Brothers, Iron Springs, and Granite Mountain drop down on 3/27/2017

Appendix:
Reg. G Schedules

Reg. G: YTD 3Q17 Free Cash Flow before Growth

($ millions)	QTD 9/30/2017	YTD 9/30/2017
Adjusted EBITDAR	**$ 811**	**$ 1,895**
Less: EME operating lease expense	(5)	(16)
Adjusted EBITDA	**$ 806**	**$ 1,876**
Interest payments	(230)	(643)
Income tax	1	(6)
Collateral / working capital / other[1]	155	(383)
Cash Flow from Operations (continuing operations)	**$ 732**	**$ 844**
Reclassifying of net receipts (payments) for settlement of acquired derivatives that include financing elements	-	2
Land Sale	-	8
Return of capital from equity investments[2]	4	22
Cost-to-Achieve[3]	14	14
Cash contribution to GenOn pension plan[4]	13	13
Collateral[1]	(86)	182
Adjusted Cash Flow from Operations	**$ 677**	**$ 1,085**
Maintenance capital expenditures, net[5]	(41)	(125)
Environmental capital expenditures, net	-	(25)
Distributions to non-controlling interests	(37)	(128)
Consolidated Free Cash Flow before Growth	**$ 599**	**$ 807**
Less: FCFbG at Non-Guarantor Subsidiaries[6]	(214)	(292)
NRG-Level Free Cash Flow before Growth	**$ 385**	**$ 514**

[1] Reflects change in NRG's cash collateral balance as of 3Q2017 including $79 MM of collateral postings from our deconsolidated affiliate (GenOn); [2] Represents cash distributions to NRG from equity investments; [3] Includes costs associated with the Transformation Plan announced on 7/12/2017; [4] Legacy GenOn pension liability retained by NRG as part of the settlement; [5] Includes insurance proceeds of $22 MM; [6] Reflects impact from NRG Yield and other excluded project subsidiaries

nrg

Reg. G: 2017 and 2018 Guidance

Appendix Table A-1: 2017 and 2018 Guidance
The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

($ millions)	2017 Previous Guidance	2017 Revised Guidance	2018 Guidance
Adjusted EBITDA	**$2,565 - $2,765**	**$2,400 - $2,500**	**$2,800 - $3,000**
Interest payments	(825)	(835)	(785)
Income tax	(40)	(25)	(40)
Working capital / other	60	60	40
Adjusted Cash Flow from Operations	**$1,760 - $1,960**	**$1,600 - $1,700**	**$2,015 - $2,215**
Maintenance capital expenditures, net	(210) - (240)	(200) - (220)	(210) - (240)
Environmental capital expenditures, net	(25) - (45)	(25) - (35)	(0) - (5)
Distributions to non-controlling interests[1]	(185) - (205)	(180) - (190)	(220) - (250)
Consolidated Free Cash Flow before Growth	**$1,290 - $1,490**	**$1,175 - $1,275**	**$1,550 - $1,750**
Less: FCFbG at Non-Guarantor Subsidiaries[2]	(420)	(420)	(380)
NRG-Level Free Cash Flow before Growth	**$870 - $1,070**	**$755 - $855**	**$1,170 - $1,370**

[1] Includes NRG Yield distributions to public shareholders, and Capistrano and Solar distributions to non-controlling interests; [2] Reflects impact from NRG Yield and other excluded project subsidiaries

Reg. G

Appendix Table A-2: Third Quarter 2017 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to (Loss)/Income from Continuing Operations

($ millions)	Gulf Coast	East/ West [1]	Generation	Retail	Renewables	NRG Yield	Corp/ Elim	Total
(Loss)/Income from Continuing Operations	**166**	**92**	**258**	**69**	**(4)**	**41**	**(174)**	**190**
Plus:								
Interest expense, net	0	5	5	1	24	75	112	217
Income tax	(2)	2	-	-	(3)	8	1	6
Depreciation and amortization	69	27	96	29	51	88	8	272
ARO Expense	4	3	7	-	1	1	-	9
Amortization of contracts	2	1	3	(1)	1	18	(1)	20
Amortization of leases	0	(2)	(2)	-	-	-	-	(2)
EBITDA	**239**	**128**	**367**	**98**	**70**	**231**	**(54)**	**712**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	(6)	7	1	(3)	(12)	32	10	28
Acquisition-related transaction & integration costs	-	-	-	-	-	-	3	3
Reorganization costs	3	-	3	5	-	-	10	18
Deactivation costs	-	2	2	-	-	-	5	7
Other non recurring charges	1	(4)	(3)	2	-	2	(1)	-
Impairments	-	1	1	-	13	-	-	14
Mark to market (MtM) (gains)/losses on economic hedges	(135)	(10)	(145)	174	(5)	-	-	24
Adjusted EBITDA	**102**	**124**	**226**	**276**	**66**	**265**	**(27)**	**806**

[1] Includes International, BETM and generation eliminations

Reg. G

Appendix Table A-3: Third Quarter 2016 Adjusted EBITDA Reconciliation by Operating Segment

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

($ millions)	Gulf Coast	East/ West [1]	Generation	Retail	Renewables	NRG Yield	Corp/ Elim	Total
(Loss)/Income from Continuing Operations	**224**	**148**	**372**	**(78)**	**2**	**50**	**(218)**	**128**
Plus:								
Interest expense, net	-	7	7	(1)	34	70	124	234
Income tax	-	(2)	(2)	-	(3)	13	20	28
Loss on debt extinguishment	-	-	-	-	-	-	50	50
Depreciation and amortization	108	26	134	26	48	75	15	298
ARO Expense	3	(6)	(3)	-	-	1	-	(2)
Amortization of contracts	5	0	5	1	1	17	(1)	23
Amortization of leases	-	(2)	(2)	-	-	-	-	(2)
EBITDA	**340**	**171**	**511**	**(52)**	**82**	**226**	**(10)**	**757**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	(1)	8	7	-	(4)	26	(2)	27
Acquisition-related transaction & integration costs	-	-	-	-	-	-	1	1
Reorganization costs	-	-	-	-	-	-	6	6
Deactivation costs	-	1	1	-	-	-	1	2
Loss on sale of business	-			-	-	-	(4)	(4)
Other non-recurring charges	15	(5)	10	(2)	-	-	2	10
Impairments	-	9	9	-	-	-	-	9
Mark to market (MtM) (gains)/losses on economic hedges	(206)	(64)	(270)	358	(1)	-	-	87
Adjusted EBITDA	**148**	**120**	**268**	**304**	**77**	**252**	**(6)**	**895**

[1] Includes International, BETM and generation eliminations

Reg. G

Appendix Table A-4: YTD Third Quarter 2017 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to (Loss)/Income from Continuing Operations

($ millions)	Gulf Coast	East/ West [1]	Generation	Retail	Renewables	NRG Yield	Corp/ Elim	Total
(Loss)/Income from Continuing Operations	**59**	**141**	**200**	**380**	**(84)**	**85**	**(461)**	**120**
Plus:								
Interest expense, net	-	22	22	3	74	235	350	684
Income tax	-	2	2	(9)	(13)	15	10	5
Loss on debt extinguishment	-	-	-	-	3	-	-	3
Depreciation and amortization	207	80	287	87	150	241	24	789
ARO Expense	11	9	20	-	2	3	(1)	24
Amortization of contracts	10	3	13	-	1	52	(1)	65
Amortization of leases	-	(6)	(6)	-	-	-	-	(6)
EBITDA	**287**	**251**	**538**	**461**	**133**	**631**	**(79)**	**1,684**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	15	19	34	(10)	(21)	79	11	93
Acquisition-related transaction & integration costs	(10)	-	(10)	-	-	2	3	(5)
Reorganization costs	3	-	3	5	-	-	28	36
Deactivation costs	-	3	3	-	-	-	9	12
Other non-recurring charges	(14)	(2)	(16)	2	9	7	(6)	(4)
Impairments	42	-	42	-	35	-	-	77
Mark to market (MtM) (gains)/losses on economic hedges	(152)	(11)	(163)	154	(8)	-	-	(17)
Adjusted EBITDA	**171**	**260**	**431**	**612**	**148**	**719**	**(34)**	**1,876**

[1] Includes International, BETM and generation eliminations

nrg

Reg. G

Appendix Table A-5: YTD Third Quarter 2016 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	Gulf Coast	East/ West [1]	Generation	Retail	Renewables	NRG Yield	Corp/ Elim	Total
Net (loss)/income	**(247)**	**198**	**(49)**	**734**	**(107)**	**116**	**(786)**	**(92)**
Plus:								
Interest expense, net	1	23	24	(1)	84	212	391	710
Income tax	-	(2)	(2)	1	(14)	25	65	75
Loss on debt extinguishment	-	-	-	-	-	-	119	119
Depreciation and amortization	251	80	331	83	143	224	45	826
ARO Expense	8	2	10	-	1	2	0	13
Amortization of contracts	11	4	15	5	1	57	(3)	75
Amortization of leases	-	(6)	(6)	-	-	-	-	(6)
EBITDA	**24**	**299**	**323**	**822**	**108**	**636**	**(169)**	**1,720**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	5	18	23	-	(2)	68	3	92
Acquisition-related transaction & integration costs	-	1	1	-	-	-	6	7
Reorganization costs	-	-	-	5	3	-	17	25
Deactivation costs	-	13	13	-	-	-	1	14
Loss on sale of business	-	-	-	-	-	-	79	79
Other non-recurring charges	19	(6)	13	-	8	3	2	26
Impairments	-	26	26	-	27	-	12	65
Impairment loss on investments	137	5	142	-	(1)	-	6	147
Mark to market (MtM) (gains)/losses on economic hedges	208	1	209	(150)	-	-	-	59
Adjusted EBITDA	**393**	**357**	**750**	**677**	**143**	**707**	**(43)**	**2,234**

[1] Includes International, BETM and generation eliminations

Reg. G

Appendix Table A-6: Expected Full Year 2017 and 2018 Free Cash Flow before Growth Reconciliation for NRG Yield (NYLD) / Other[1]: The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

	NYLD / Other		
($ millions)	2017 Previous Guidance	2017 Revised Guidance	2018 Guidance
Adjusted EBITDA	**1,265**	**1,250**	**1,355**
Interest payments	(350)	(350)	(360)
Collateral / working capital / other	(143)	(143)	(185)
Cash Flow from Operations	**772**	**757**	**810**
Maintenance capital expenditures, net	(35)	(35)	(40)
Environmental capital expenditures, net	-	-	-
Distributions to NRG	(142)	(127)	(180)
Distributions to non-controlling interests	(175)	(175)	(210)
Free Cash Flow before Growth	**420**	**420**	**380**

[1] Includes NRG Yield and other assets (primarily Aqua Caliente, Ivanpah, and Capistrano)

Reg. G

Appendix Table A-7: 2017 and 2018 Adjusted EBITDA Guidance Reconciliation: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

	2017 Adjusted EBITDA Previous Guidance		2017 Adjusted EBITDA Revised Guidance		2018 Adjusted EBITDA Revised Guidance	
($ millions)	**Low**	**High**	**Low**	**High**	**Low**	**High**
GAAP Net Income [1]	360	560	55	155	410	610
Income tax	80	80	10	10	20	20
Interest Expense	825	825	835	835	785	785
Depreciation, Amortization, Contract Amortization and ARO Expense	1,150	1,150	1,170	1,170	1,180	1,180
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	110	110	130	130	135	135
Other Costs [2]	40	40	200	200	270	270
Adjusted EBITDA	**$2,565**	**$2,765**	**$2,400**	**$2,500**	**$2,800**	**$3,000**

[1] For purposes of guidance, discontinued operations are excluded and fair value accounting related to derivatives are assumed to be zero; [2] Includes deactivation costs, reorganization costs associated with the Transformation plan, gain on sale of businesses, asset write-offs, impairments and eVgo California settlement

Reg. G

Appendix Table A-8: Expected Full Year 2017 and 2018 Adjusted EBITDA Reconciliation for ROFO/ Renewable /Conventional[1,2], and NRG Yield[2]

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

($ millions)	**2017** ROFO/ Renewable/ Convention	**2017** NRG Yield	**2018 Pro-Forma** ROFO/ Renewable/ Convention
Net (loss)/income	**(55)**	**100**	**69**
Plus:			
Income tax	-	20	-
Interest expense, net	75	310	-
Depreciation, Amortization, Contract Amortization, and ARO Expense	250	400	50
EBITDA	**270**	**830**	**119**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	(20)	80	-
Deactivation costs	-	-	3
Other non-recurring charges	45	25	-
Mark to market (MtM) losses on economic hedges	20	-	3
Plus: Operating lease expense	21	-	21
Adjusted EBITDAR	**336**	**935**	**146**
Less: Operating lease expense	(21)	-	(21)
Adjusted EBITDA - Standalone	**315**	**935**	**125**

[1] In accordance with GAAP, restated to reflect impact of Utah Solar and NRG's 31% interest in Agua Caliente drop down to NRG Yield; [2] Guidance as of the NRG Yield 3Q 2017 earnings call

Reg. G

Appendix Table A-9: Prior 6 quarters Adjusted EBITDA Reconciliation for NRG post deconsolidation of GenOn Energy
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to (Loss)/Income from Continuing Operations

($ millions)	1Q 2016	2Q 2016	3Q 2016	4Q 2016	1Q 2017	2Q 2017	3Q 2017
(Loss)/Income from Continuing Operations	**(57)**	**(163)**	**128**	**(892)**	**(170)**	**99**	**190**
Plus:							
Income tax	22	25	28	(70)	(5)	4	6
Interest expense, net	240	236	234	176	222	244	217
Loss on debt extinguishment	(11)	80	50	23	2	0	0
Depreciation, Amortization, Contract Amortization, and ARO Expense	300	290	370	374	287	287	299
EBITDA	**494**	**468**	**757**	**(389)**	**336**	**634**	**712**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	34	32	27	14	18	47	28
Deactivation costs	8	5	2	3	1	4	7
Other non-recurring charges	166	160	12	768	13	59	35
Mark to market (MtM) losses on economic hedges	(61)	33	87	75	18	(59)	24
Adjusted EBITDA	**641**	**698**	**895**	**471**	**386**	**685**	**806**

Reg. G

Appendix Table A-10: Adjusted EBITDA and FCFbG Guidance Reconciliation for Asset Sales: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

($ millions)	Asset to be Divested
Net (loss)/income	**194**
Plus:	
Income tax	-
Interest expense, net	405
Depreciation, Amortization, Contract Amortization, and ARO Expense	730
EBITDA	**1,329**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	71
Adjusted EBITDA	**1,400**
Interest payments	(395)
Collateral / working capital / other	(30)
Cash Flow from Operations	**975**
Maintenance capital expenditures, net	(70)
Distributions to non-controlling interests	(235)
Free Cash Flow before Growth - Consolidated	**670**
Less: Cash distributions to NRG (e.g. FCFbG at NRG-Level)	(380)
Free Cash Flow before Growth - Residual	**290**

[1] For purposes of guidance, fair value accounting related to derivatives are assumed to be zero; [2] Includes deactivation costs, gain on sale of businesses, asset write-offs, impairments and eVgo California settlement

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.