NRG Energy Inc.

Fourth Quarter and Full Year 2017 Earnings Presentation

March 1, 2018

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, 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 GenOn's emergence from bankruptcy, 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, 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 March 1, 2018. 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

Strong Market and Financial Outlook;
Delivered on 2017 Priorities, Reaffirming 2018 Guidance

Announced Over 90% of Target Asset Sales and
Exceeded 2017 Cost Savings Target

Announcing $1 Bn Share Buyback Authorization;
First $500 MM Program to be Launched Immediately

Transformation Plan
Score Card Update

Score Card
As of 12/31/2017

2017 Progress

($ millions)	2017 Target	*% achieved*	2017 Realized	2018 Target
Accretive & Recurring:				
Cost Savings	65	*231%*	150	500
Margin Enhancement*	0	-	-	30
Total EBITDA - Accretion	**$65**	***231%***	**$150**	**$530**
Maintenance Capex*	0	-	-	30
Total Recurring FCFbG - Accretion	**$65**	***231%***	**$150**	**$560**
Non-Recurring:				
Working Capital Improvement	175	*126%*	221	85
Cost to Achieve Total Transformation Plan	(115)	-	(44)	(246)
Total Non-Recurring	**$60**	**-**	**$177**	**($161)**
Annual Cash Accretion	**$125**	***217%***	**$327**	**$399**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$125**	***217%***	**~$327**	**$726**

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

Transformation Plan Progress Through Today

Cost Savings and Margin Enhancements:

- ☑ $150 MM of realized cost savings in 2017
- ☑ $221 MM of working capital reduced in 2017
- ☑ EBITDA margin enhancement underway

Portfolio Optimization:

- ☑ ***New*:** Announcing sale of BETM[1] for $70 MM
- ☑ Announced $3.0 Bn in asset sales to date
- ☑ Updated target cash proceeds of $3.2 Bn from asset sales

Capital Allocation:

- ☑ ***New*:** Authorized $1 Bn share buyback; first $500 MM program to be launched immediately
- ☑ On track to achieve 3.0x net debt / Adj. EBITDA in 2018
- ☑ $8 Bn of consolidated debt identified to be removed due to asset sales

Transformation Plan Progress on Track to Create Significant Shareholder Value

[1] BETM=Boston Energy Trading and Marketing

Business Update

Business Highlights

- ☑ Achieved top decile safety performance in 2017; second best safety year in company history
- ☑ Executed on 2017 Transformation Plan priorities with 2018 on track
- ☑ Retail business delivers 4th consecutive year of Adj. EBITDA growth
- ☑ Demonstrated operational resiliency during Hurricane Harvey
- ☑ GenOn reorganization plan confirmed by court

Financial Highlights

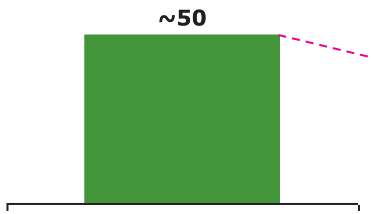
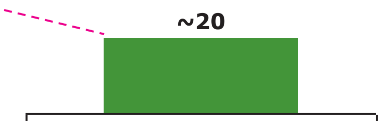
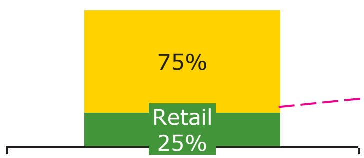
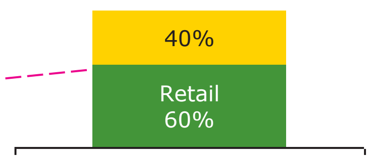
($ millions)	2017A	2017 Guidance
Adjusted EBITDA	$2,373	$2,400 - $2,500
Free Cash Flow Before Growth:		
NRG Consolidated	$1,304	$1,175 - $1,275
NRG Level	$897	$755 - $855

Reaffirming 2018 Guidance Ranges:

$2,800 - $3,000 Adjusted EBITDA
$1,550 - $1,750 Consolidated FCFbG
$1,170 - $1,370 NRG-Level FCFbG

Executed on 2017 Strategic Priorities; Reaffirming 2018 Financial Guidance

Portfolio Update

	2016[1]	Today (Pro forma 2018)	
1 Streamlined Portfolio Focuses on Texas and East	 Portfolio Capacity (GW)	 Portfolio Capacity (GW)	**60%** Decrease in Capacity
2 Steady Retail Customer Count[2]	~2.89 MM	~2.94 MM[3]	**~2%** Growth per year
3 Earnings Driven Increasingly by Retail Business	 2016A Adj. EBITDA	 2018E Adj. EBITDA	**60%** EBITDA from Retail
4 Significantly Enhanced FCF/EBITDA Conversion	21%	63%[4]	**Increasing** Conversion to NRG-level FCFbG

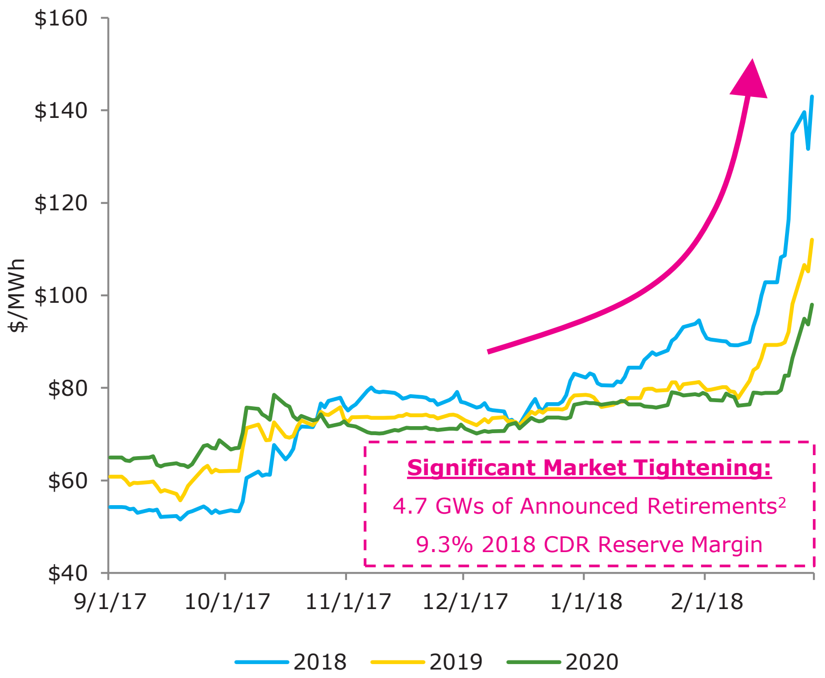
Evolving NRG Model Driving Greater Value through Efficiency, Simplification and Focus

[1] 12/31/2016 capacity; [2] Includes Mass and C&I retail customers; [3] Customer count as of 12/31/2017; [4] Based on midpoint of 2018 guidance as of 3/01/2018 pro forma for asset sales

Market Outlook

Strong Price Trajectory in ERCOT Due to Tighter Market Conditions…

Houston On-Peak Summer (Jul-Aug) Power Prices[1]



…with Strong Call to Action for Reform Across All Markets

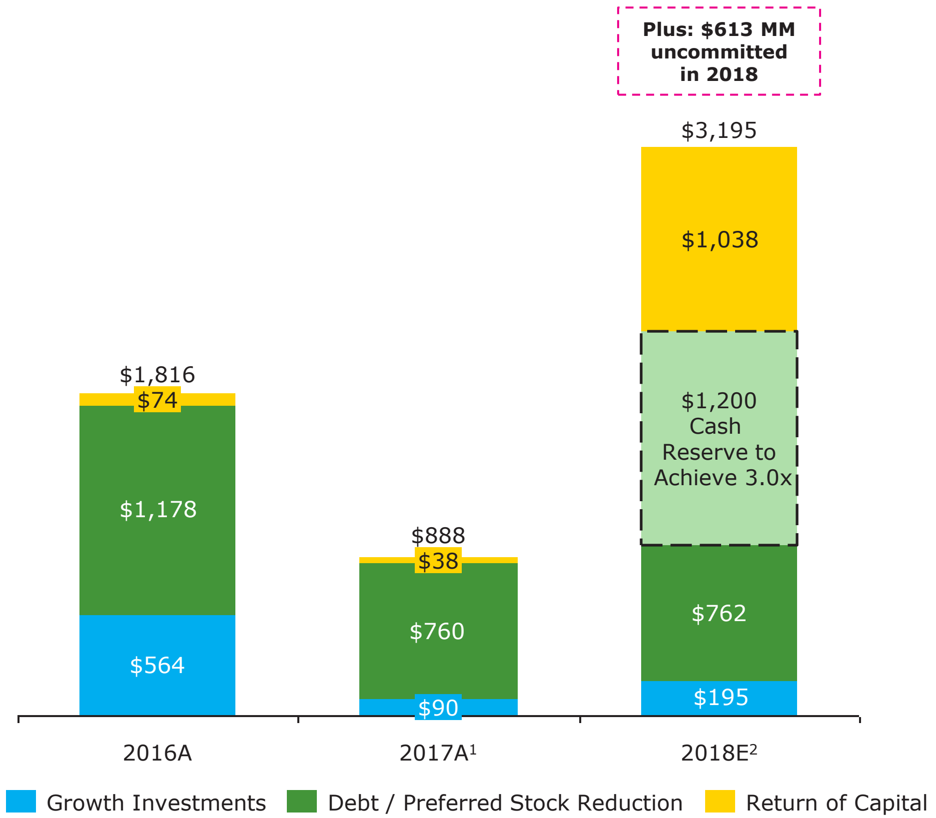
- PJM Energy Market **focus on reflecting reliability** costs by allowing inflexible units to set price
- PJM Board plans to submit **capacity re-pricing proposal** and MOPR expansion
- Push for **improved retail experience** in Maryland and Pennsylvania by allowing direct customer/supplier relationship
- **Retail choice** is expanding nationally, with Nevada next up to decide on statewide choice this fall

Power Markets Stabilizing With Significant Upside in 2018 and Beyond; Continued NRG Advocacy for Competitive Retail and Generation Markets

[1] As of 2/28/2018; [2] Announced retirements include Big Brown (1,208 MW), Monticello (1,865 MW), Sandow (1,200 MW), Barney Davis (330 MW), and Spencer (118 MW)

Capital Allocation Update

Capital Allocation Mix ($ MM)



Capital Allocation Priorities

- ☑ Maintain top decile safety and operational excellence
- ☑ Reduce Net Debt/Adj. EBITDA to 3.0x by YE 2018
- Invest in projects with at least 12-15% unlevered pre-tax return, 5-year or less payback
- Return excess cash to shareholders

Strengthened Business Enables Shareholder Return

[1] Excludes GenOn Settlement ($138 MM) and Transformation Plan Cost to Achieve ($44 MM); [2] Excludes GenOn Settlement ($178 MM) and Transformation Plan Cost to Achieve ($246 MM)

Financial Update

2017 Financial Summary 2018 Guidance Reaffirmed

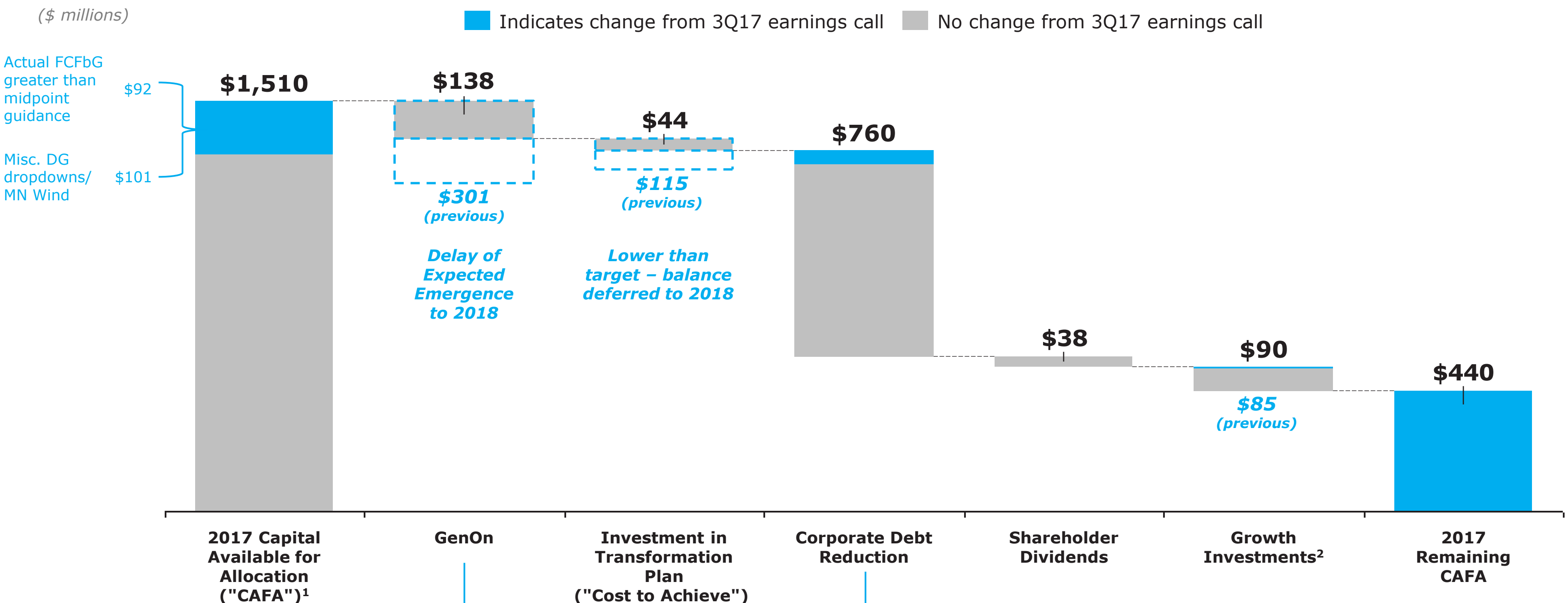
	2017	2018			
($ millions)	Full Year Results	Guidance	*Full Year Impact of Targeted Asset Sales* — *Announced*	*Full Year Impact of Targeted Asset Sales* — *To be Completed*	Pro Forma[2]
Generation & Renewables[1]	$615	$950 – $1,050	*($255)*	*($100)*	~$650
Retail	825	900 – 1,000	–	–	~950
NRG Yield	933	950	*(950)*	–	–
Adjusted EBITDA	**$2,373**	**$2,800 - $3,000**	*($1,205)*	*($100)*	**~$1,600**
Consolidated Free Cash Flow before Growth ("FCFbG")	**$1,304**	**$1,550 - $1,750**	*($590)*	*($50)*	**~$1,000**
NRG-Level FCFbG	**$897**	**$1,170 - $1,370**	*($245)*	*($20)*	**~$1,000**
Adjusted EBITDA to FCFbG Conversion	*38%*	*~44%*			*~63%*

	2018 Includes	2020 Run Rate	Incremental Beyond 2018
Cost Savings	$500	$590	$90
Margin Enhancements	30	215	185
Incremental Impact to Adjusted EBITDA			$275

- ~$3 Bn[3] of asset sales announced or closed to date:
  - Renewables/NYLD stake: $1,375 MM
  - South Central: 1,000 MM
  - NYLD ROFO Drop Downs to NRG Yield: 407 MM
  - 2H 2017 dropdowns & sale of MN Wind: 150 MM
  - Announcing sale of BETM: 70 MM
- Completed refinancings and $604 MM of planned corporate debt reduction resulting in incremental annual interest savings of $55 MM
- Non-cash impairment charge of $1.8 Bn on fixed assets and goodwill

[1] Includes Corporate Segment; [2] Based on midpoint of guidance range; [3] Excludes transaction costs; subject to working capital and other customary purchase price adjustments

2017 NRG-Level Capital Allocation



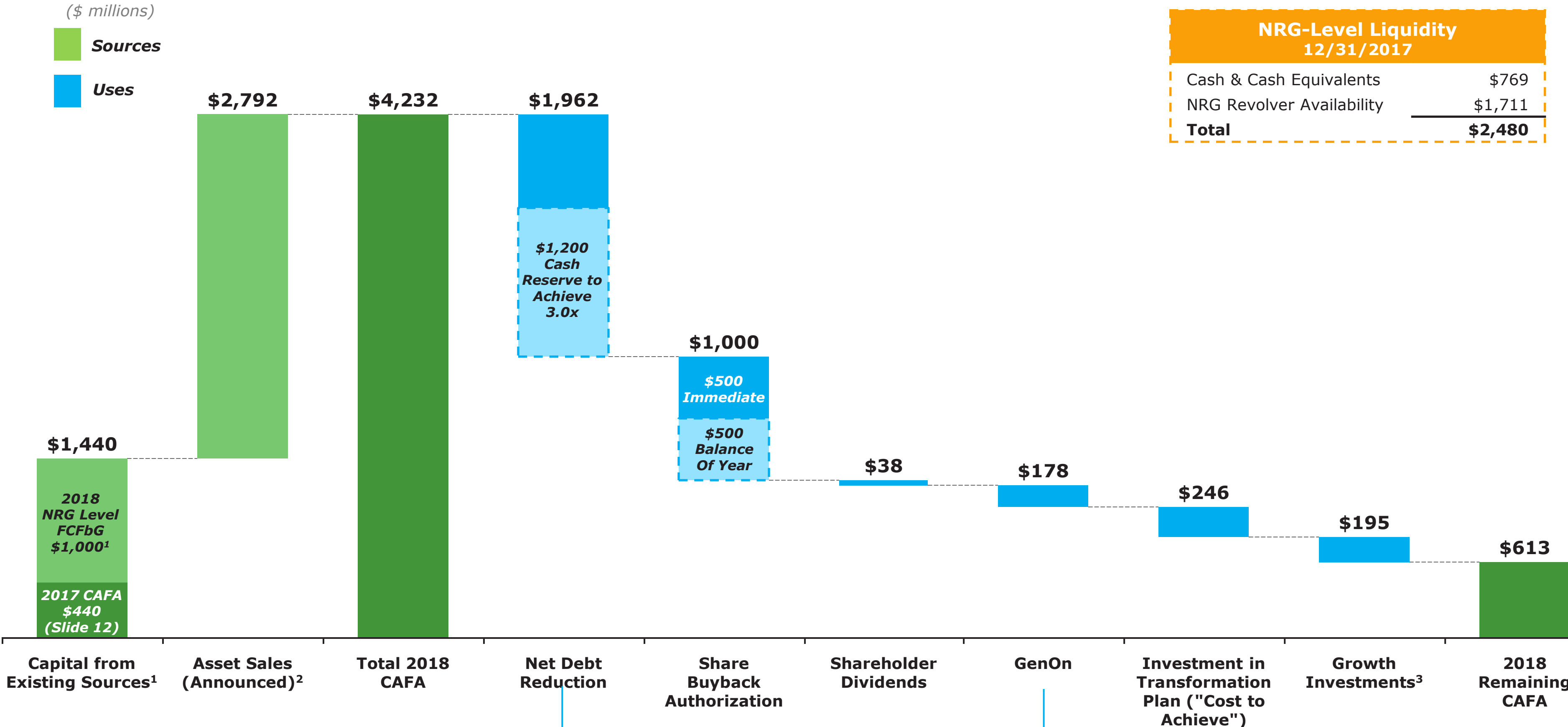
Revolver draw	$125[3]
Pension	13

Retirement of 2018 Notes	$398
Retirement of 2021 Notes	206
Term Loan Amortization	19
Midwest Gen Debt Amortization[4]	80
Refi Fees and premiums on notes	57

Completed 2017 Debt Capital Allocation Plan with Retirement of 2018 and 2021 Senior Notes; GenOn Settlement Capital Deferred to 2018 Pending Emergence from Bankruptcy

[1] CAFA = 2016 YE cash & cash equivalents at NRG level of $570 MM less minimum cash reserve of $500 MM (net of $71 MM in NRG Level cash collateral postings) plus 2017 NRG-level FCFbG of $897 MM plus $472 MM of proceeds related to dropdowns and renewable asset financings and sales (see Appendix slide 38 for details); [2] Net of financing; [3] $125 MM drawn by GenOn on intercompany revolver to be repaid upon emergence; [4] $80 MM of 2017 capacity revenue sold forward in 2016; 2017 payment to counterparty treated as debt amortization for accounting purposes

2018 Capital Allocation



NRG-Level Liquidity 12/31/2017

Cash & Cash Equivalents	$769
NRG Revolver Availability	$1,711
Total	**$2,480**

Debt Reduction	$ 640
Term Loan Amortization	19
Midwest Gen Debt Amortization[4]	103
Cash Reserve to achieve 3.0x	1,200

Settlement	$ 261
Repayment of Loan by GenOn	(125)
Pension and other[5]	42

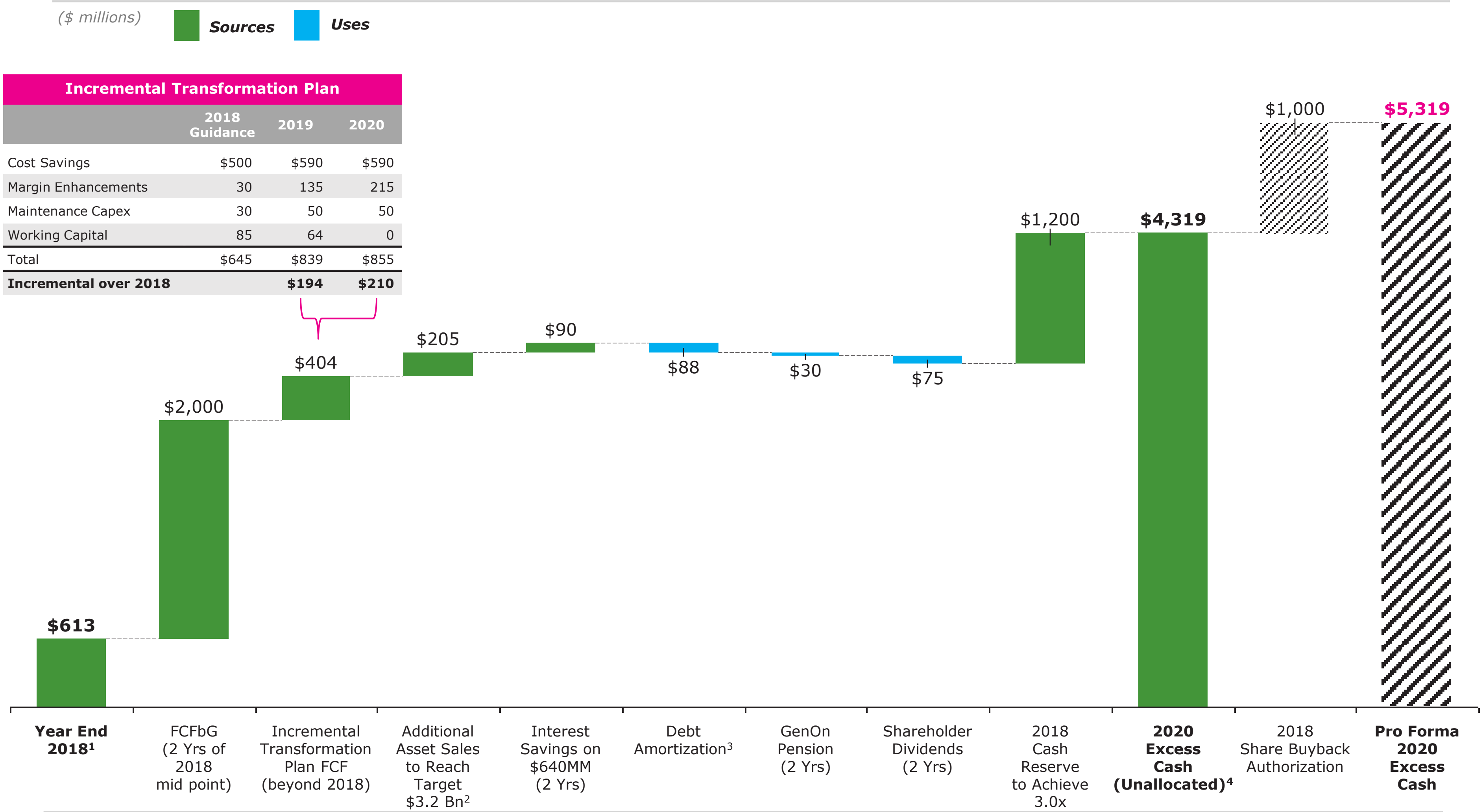
[1] Capital from Existing Sources includes: 2017 YE cash & cash equivalents at NRG level of $769 MM less minimum cash of $500 MM (net of $171 MM in cash collateral postings) plus NRG-level FCFbG pro forma for divestitures guidance of $1,000 MM; [2] Reflects $2,375 MM of asset sales and $407 MM of dropdowns announced on February 7, 2018, less estimated transaction fees of ~$60 MM, plus $70 MM for sale of Boston Energy Trading & Marketing (BETM); [3] Net of financing; [4] $103 MM of 2018 capacity revenue sold forward in 2016; 2018 payment to counterparty treated as debt amortization for accounting purposes; [5] $28 MM agreed as part of settlement plus $14 MM in pension funding in 2018

Updated Pro Forma Excess Cash (2020)

($ millions)

Incremental Transformation Plan

	2018 Guidance	2019	2020
Cost Savings	$500	$590	$590
Margin Enhancements	30	135	215
Maintenance Capex	30	50	50
Working Capital	85	64	0
Total	$645	$839	$855
Incremental over 2018		**$194**	**$210**



Up to ~$4.3 Bn of Excess Cash[4] Through 2020 After 2018 Share Buybacks

[1] Excludes cash of $500 MM for collateral posting and other liquidity needs; [2] Represents $275 MM of remaining target sales per February Asset Sale presentation less $70 MM for sale of BETM reflected in the 2018 YE CAFA; [3] 2 years of 1% Term Loan amortization plus $49 MM of remaining Midwest Gen debt amortization; [4] Cumulative through 2020, assumes 2018 cash reserve of $1.2 Bn released by 2020

NRG's Capital Structure & Corporate Credit Metrics

($ millions)

Debt Balances as of 12/31/2017

Consolidated	Less: Impact of Asset Sales	Pro-Forma	Less: Ivanpah/ MWG	Recourse Debt
$16,638	($8,118)	$8,520	($1,334)	$7,186

NYLD / Renewables	(6,711)	Renewables (Ivanpah)	(1,182)
Carlsbad	(427)	MWG	(152)
To be completed	(980)		

	2018 Pro-Forma for Divestitures
Recourse Debt *(12/31/2017)*[1]	**$7,186**
2018 Term Loan Amortization	(19)
Additional Debt Reduction	(640)
Pro Forma Corporate Debt	**~$6,530**
Cash & Cash Equivalents @ NRG-Level /Minimum Cash	(500)
Cash Reserve to meet 3.0x target	(1,200)
Pro Forma Corporate Net Debt	**~$4,830**
Pro-Forma Adj. EBITDA[2]	**$1,600**
Less:	
Ivanpah and Midwest Gen Adjusted EBITDA	(225)
Add:	
Ivanpah and Midwest Gen Cash Distributions to NRG	65
Other Adjustments[3]	150
Total Recourse EBITDA	**$1,590**
Corporate Net Debt/Corporate EBITDA	**3.0x**

Excludes $613 MM of 2018 CAFA remaining to be allocated

Reserving $1.2 Bn of Cash to Maintain 3.0x Corporate Credit Ratio

[1] Includes NRG Energy Inc. term loan facility, senior notes, revolver, capital leases and tax exempt bonds; [2] See slide 11; [3] Reflects non-cash expenses (i.e. nuclear amortization, equity compensation amortization, and bad debt expense) that are included in Adjusted EBITDA

Closing Remarks

2018 Priorities and Expectations

- **Deliver on Financial and Operational Objectives**

- **Execute on NRG Transformation Plan 2018 Objectives[1]**
  - $500 MM of EBITDA-accretive cost savings
  - $30 MM of EBITDA-accretive margin enhancement
  - $205 MM in remaining targeted asset sales announced to be announced

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- **Complete Announced Asset Sales and Dispositions**
  - Renewables, South Central and BETM expected to close in second half of 2018
  - GenOn expected to emerge from bankruptcy; transition services provided through 6/30/2018, with ability to extend to 9/30/2018

- **Provide Long-Term Strategy on March 27, 2018 Analyst Day**

Appendix

Transformation Plan Score Card

Transformation Plan Target 12/31/2017

($ millions)	2017A	2018E	2019E	2020 / Run Rate
Accretive & Recurring:				
Cost Savings	150	500	590	590
Margin Enhancement	0	30	135	215
Total EBITDA - Accretion	**$150**	**$530**	**$725**	**$805**
Maintenance Capex	0	30	50	50
Total Recurring FCFbG Accretion	**$150**	**$560**	**$775**	**$855**
Non-Recurring:				
Working Capital Improvement	221	85	64	--
Cost to Achieve Total Transformation Plan	(44)	(246)	--	--
Total Non-Recurring	**$177**	**($161)**	**64**	**--**
Annual Cash Accretion	**$327**	**$399**	**$839**	**$855**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$327**	**$726**	**$1,565**	**$2,420**

Shifting Transformation Plan non-recurring targets in forward years due to achievement levels in 2017

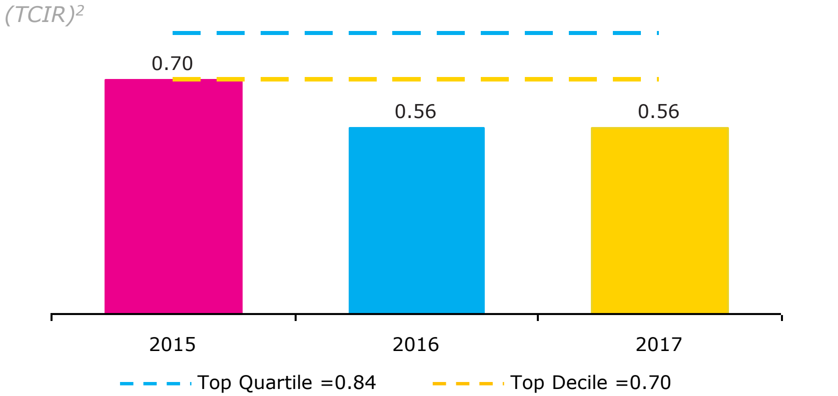
Previous Target as of 7/12/2017

Non-Recurring:	2017	2018	2019
Working Capital Improvement	175	85	110
Cost to Achieve Total Transformation Plan	(115)	(175)	--

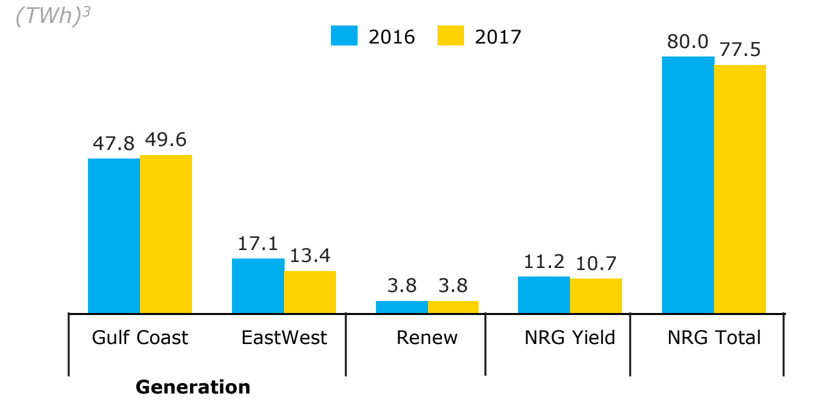
Appendix: Operations

Generation/Business: Operational Metrics

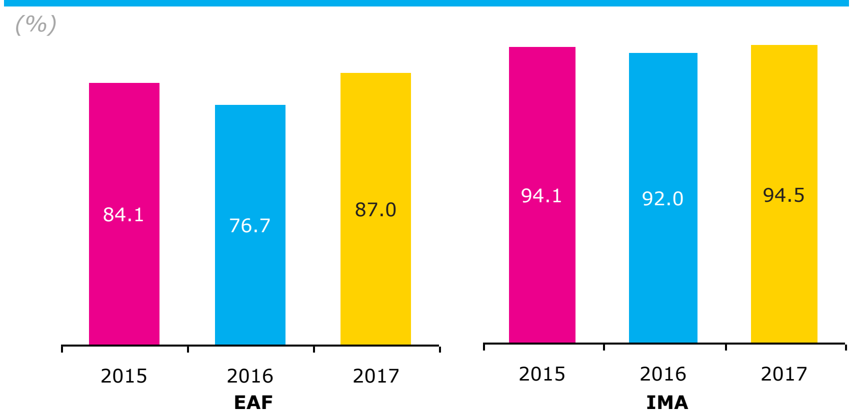
Safety[1]



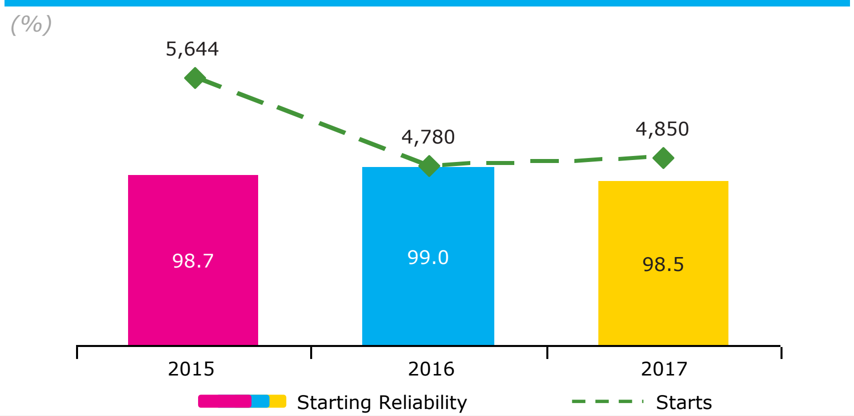
Production



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

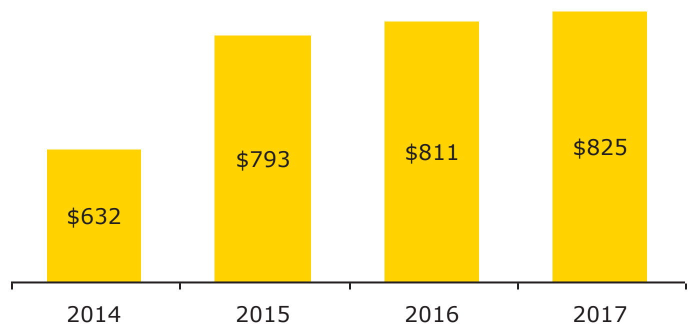
Retail: Operational Metrics

2017 Highlights

- Delivered 4th year in a row of earnings growth with $825 MM of Adjusted EBITDA in 2017
- Expanded portfolio by ~58,000 recurring Mass customers over the year
- Overcame adverse weather conditions vs 2016, including Hurricane Harvey, with cost efficiencies from continuous improvement and the Transformation Plan

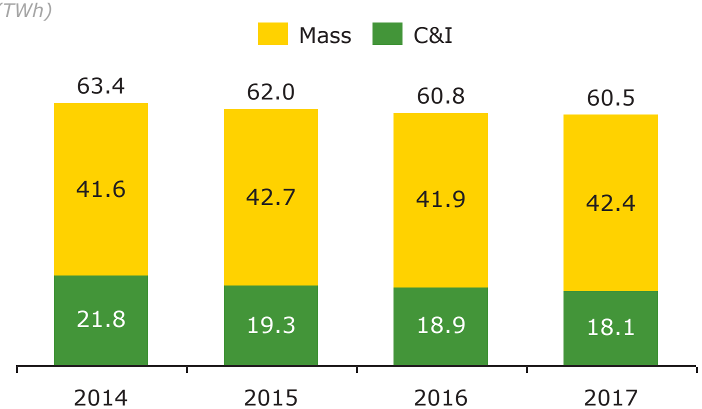
Retail Earnings

Adjusted EBITDA ($ millions)



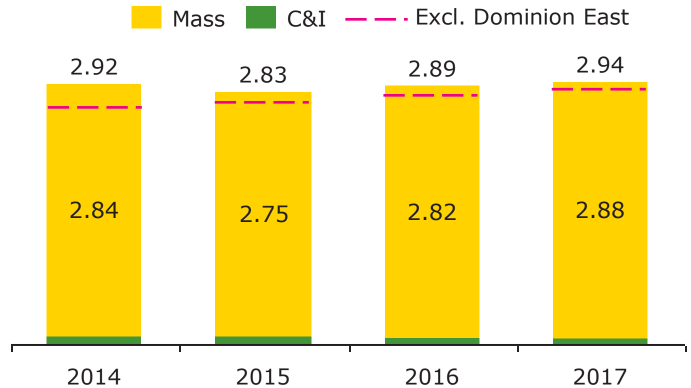
Delivered Volume[1]

Load (TWh)



Recurring Customer Count

Count[2] (millions)

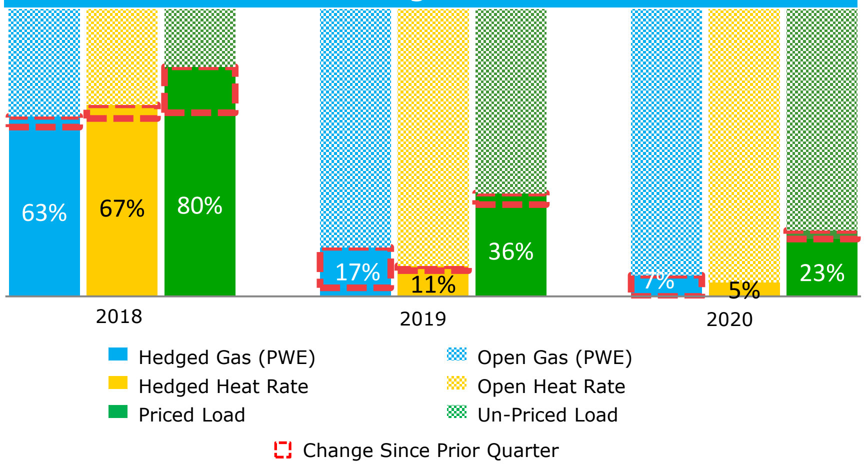


Another Strong Year Driven by Disciplined Execution

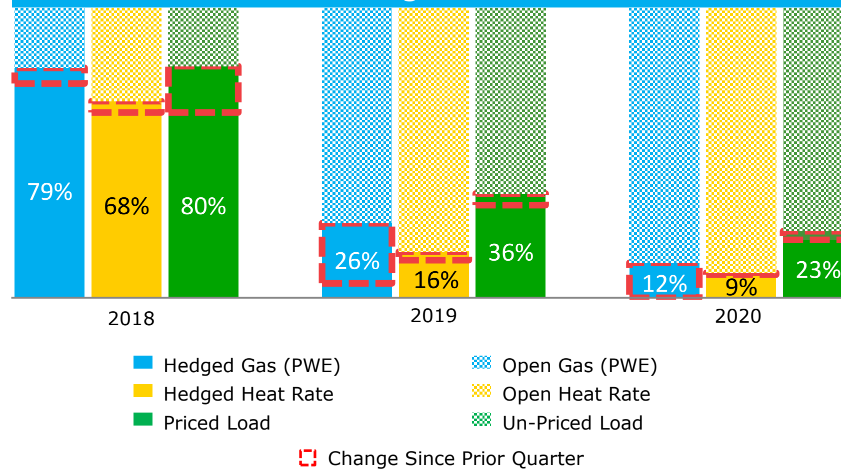
[1] Volumes exclude load associated with customer self-supply; [2] Mass count includes recurring customers that subscribe to one or more recurring services, such as electricity and natural gas; C&I count reflects electricity meter count

Pro-Forma Portfolio[1]
Managing Commodity Price Risk

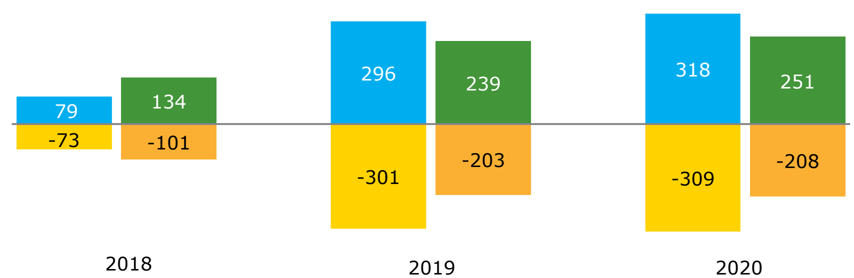
Total Portfolio Generation and Retail Hedge Position[1,2]



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



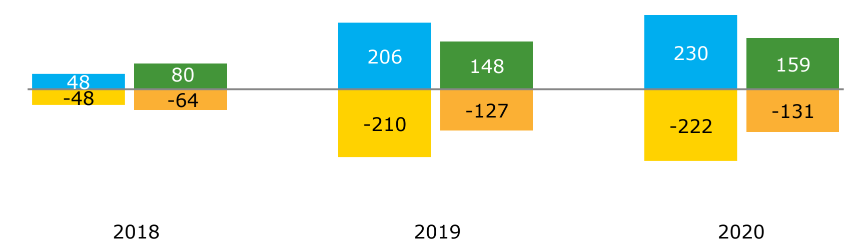
Total Portfolio Sensitivity to Gas Price and Heat Rate[1,3]



	2018	2019	2020
Henry Hub Gas as of 2/27	2.85	2.79	2.77

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 2/27	2.85	2.79	2.77

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 2/27/2018, includes TEXAS, PJM, NY, NE, CAISO & Cottonwood, excludes GenOn, MISO, Yield & Renew; [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 97%, 38%, and 23% for 2018, 2019, and 2020, respectively

Hedge Disclosure: Coal and Nuclear Operations

Coal & Nuclear Portfolio [1]	Texas			East		
	2018	2019	2020	2018	2019	2020
Net Coal and Nuclear Capacity (MW)[2]	5,329	5,329	5,329	3,267	3,267	3,267
Forecasted Coal and Nuclear Capacity (MW)[3]	4,160	3,931	3,861	1,412	1,198	1,048
Total Coal and Nuclear Sales (GWh)[4]	26,256	10,037	4,563	12,498	1,535	654
Percentage Coal and Nuclear Capacity Sold Forward[5]	72%	29%	13%	101%	15%	7%
Total Forward Hedged Revenues [6]	$1,116	$326	$147	$405	$47	$20
Weighted Average Hedged Price ($ per MWh)[6]	$42.51	$32.47	$32.23	$32.43	$30.58	$30.57
Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$2.24	$2.63	$2.60	$2.85	$2.93	$2.72
Gross Margin Sensitivities $ in MM: Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	$7	$102	$123	$41	$104	$107
Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	($28)	($133)	($150)	($21)	($77)	($72)
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$54	$91	$99	$26	$57	$60
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	($43)	($79)	($86)	($21)	($48)	($46)

[1] Portfolio as of 2/27/2018. Includes TEXAS and PJM; Excludes MISO
[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 2/27/2018 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 2/27/2018 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 2015 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

Commodity Prices

Forward Prices[1]	2018	2019	2020	Annual Average for 2018-2020
NG Henry Hub ($/Mmbtu)	$2.85	$2.79	$2.77	$2.80
PRB 8800 ($/ton)	$12.63	$12.41	$12.30	$12.45
ERCOT Houston Onpeak ($/MWh)	$49.27	$43.16	$40.41	$44.28
ERCOT Houston Offpeak ($/MWh)	$23.21	$21.91	$21.43	$22.18
PJM West Onpeak ($/MWh)	$38.77	$34.96	$34.70	$36.14
PJM West Offpeak ($/MWh)	$28.71	$25.94	$25.83	$26.83

[1] Prices as of 2/27/2018

Fuel Statistics

	4Q		YTD	
Domestic[1]	**2017**	**2016**	**2017**	**2016**
Coal Consumed (mm Tons)	5.4	5.3	23.4	23.0
PRB Blend	**98%**	**86%**	**94%**	**83%**
East	95%	99%	96%	96%
Gulf Coast	98%	82%	94%	78%
Bituminous	**1%**	**0%**	**1%**	**1%**
East	5%	1%	4%	4%
Lignite	**1%**	**14%**	**5%**	**16%**
Gulf Coast	2%	18%	6%	22%
Cost of Coal ($/Ton)	**$ 31.70**	**$ 30.23**	**$ 32.19**	**$ 31.88**
Cost of Coal ($/mmBtu)	**$ 1.84**	**$ 1.82**	**$ 1.89**	**$ 1.92**
Cost of Gas ($/mmBtu)	**$ 2.78**	**$ 2.79**	**$ 3.09**	**$ 2.56**

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

Q4 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	11,598	11,401	197	2%	92%	36%	84%	36%
East/West	3,171	3,382	(211)	(6%)	84%	11%	77%	12%
Renewables	955	901	54	6%	90%	36%	97%	35%
NRG Yield[4]	2,631	2,615	16	1%	97%	21%	98%	21%
Total	**18,355**	**18,299**	**56**	**0%**	**89%**	**24%**	**84%**	**24%**
Gulf Coast – Texas Nuclear	2,575	2,092	483	23%	100%	99%	83%	81%
Gulf Coast – Texas Coal	6,108	5,558	550	10%	90%	66%	80%	60%
Gulf Coast – South Central Coal	679	673	6	1%	83%	23%	73%	28%
East Coal	1,737	2,131	(394)	(18%)	80%	18%	63%	21%
Baseload	**11,099**	**10,454**	**645**	**6%**	**86%**	**44%**	**73%**	**42%**
Renewables Solar	394	346	48	14%	97%	42%	99%	42%
Renewables Wind	561	555	6	1%	88%	35%	96%	33%
NRG Yield Solar	239	226	13	6%	99%	22%	99%	21%
NRG Yield Wind	1,252	1,460	(208)	(14%)	96%	27%	97%	32%
Intermittent	**2,446**	**2,587**	**(141)**	**(5%)**	**95%**	**29%**	**97%**	**31%**
East Oil	102	22	80	364%	79%	0%	73%	0%
Gulf Coast – Texas Gas	711	717	(6)	(1%)	94%	6%	84%	6%
Gulf Coast – South Central Gas	1,525	2,361	(836)	(35%)	93%	26%	96%	41%
East Gas	176	212	(36)	(17%)	86%	4%	90%	3%
West Gas	1,156	1,017	139	14%	98%	28%	97%	24%
NRG Yield Conventional	637	432	205	47%	98%	15%	99%	10%
NRG Yield Thermal[4]	503	497	6	1%	78%	8%	95%	7%
Intermediate / Peaking	**4,810**	**5,258**	**(448)**	**(9%)**	**91%**	**11%**	**88%**	**12%**

[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

FY 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	49,574	47,827	1,747	4%	90%	39%	88%	39%
East/West	13,373	17,114	(3,741)	(22%)	85%	12%	78%	16%
Renewables	3,836	3,827	9	0%	95%	38%	97%	35%
NRG Yield[4]	10,687	11,230	(543)	(5%)	96%	21%	97%	23%
Total	**77,470**	**79,998**	**(2,528)**	**(3%)**	**89%**	**26%**	**86%**	**27%**
Gulf Coast – Texas Nuclear	9,509	9,559	(50)	(1%)	94%	92%	95%	93%
Gulf Coast – Texas Coal	24,757	21,738	3,019	14%	91%	67%	85%	59%
Gulf Coast – South Central Coal	3,865	3,459	406	12%	85%	34%	79%	39%
East Coal	8,407	11,096	(2,689)	(24%)	83%	22%	64%	29%
Baseload	**46,538**	**45,852**	**686**	**1%**	**87%**	**47%**	**77%**	**48%**
Renewables Solar	1,740	1,634	106	6%	98%	51%	100%	44%
Renewables Wind	2,096	2,193	(97)	(4%)	94%	35%	96%	33%
NRG Yield Solar	1,248	1,281	(33)	(3%)	99%	30%	99%	31%
NRG Yield Wind	5,597	6,010	(413)	(7%)	97%	31%	98%	33%
Intermittent	**10,681**	**11,118**	**(437)**	**(4%)**	**96%**	**33%**	**98%**	**33%**
East Oil	319	318	1	0%	85%	0%	87%	0%
Gulf Coast – Texas Gas	4,428	6,379	(1,951)	(31%)	87%	10%	89%	14%
Gulf Coast – South Central Gas	7,015	6,692	323	5%	92%	31%	93%	32%
East Gas	1,223	1,862	(639)	(34%)	86%	5%	83%	9%
West Gas	3,424	3,838	(414)	(11%)	92%	21%	93%	23%
NRG Yield Conventional	1,809	1,697	112	7%	94%	10%	95%	10%
NRG Yield Thermal[4]	2,033	2,242	(209)	(9%)	92%	7%	93%	24%
Intermediate / Peaking	**20,251**	**23,028**	**(2,777)**	**(12%)**	**89%**	**12%**	**89%**	**14%**

[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:

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

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

- 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	Average Price ($/MW-day)[1]	MWs Cleared	Average Price ($/MW-day)[1]	MWs Cleared
		Base Product		Capacity Performance Product	
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:

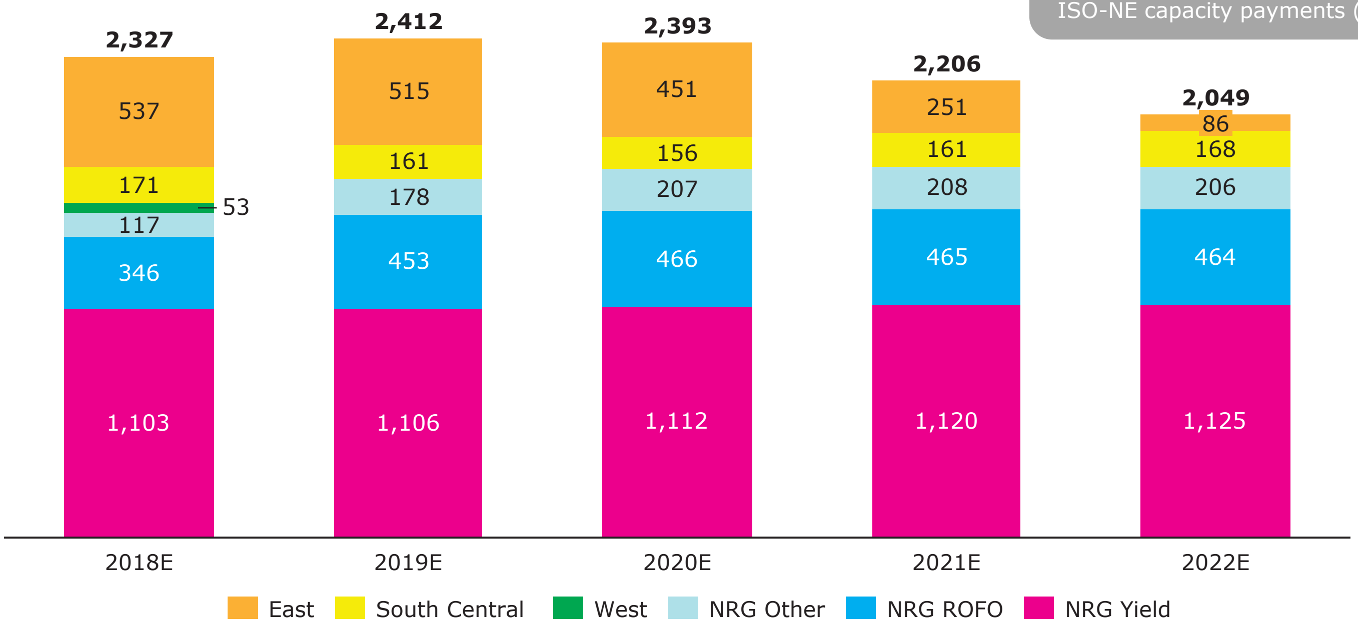
- Data reflects physical location of generating unit; reflects demonstrated summer capacity with NRG's ownership applied, including conversions
- Excludes NYLD assets Dover 104 MW in DPL and Paxton Creek 12 MW in MAAC
- Data as of 6/30/2017

Appendix: Finance

Fixed Contracted and Capacity Revenue (4Q17)

($ millions)

Excludes Penalties and Uncleared:
NYISO capacity payments (post 2019)
PJM capacity payments (post 20/21 BRA)
ISO-NE capacity payments (post 21/22 FCA12)



Notes:

- East includes cleared capacity auction for PJM through May 2021, New England ISO Forward Capacity Auction 12(FCA12) through May 2022; NY on rolling forward basis
- West includes committed Resource Adequacy contracts & CPM contracts
- South Central includes capacity sold into PJM/MISO auctions and Co-Op contracted revenues
- NRG ROFO includes all wind, solar and conventional assets which are part of current ROFO agreement including projects under construction (Carlsbad)
- NRG Other includes renewable assets which are not part of current ROFO agreement and preferred resources projects
- NRG Yield includes contracted capacity, contracted energy and contracted steam revenues

2017 Net Capital Expenditures

($ millions)	Maintenance[1]	Environmental	Growth[2]	Total
Generation				
Gulf Coast	$94	$1	$4	$99
East/West[3]	21	24	321	366
Retail	30	-	52	82
Renewables	5	-	506	511
NRG Yield	27	-	3	30
Corporate	16	-	7	23
Total Cash Capital Expenditures	**$193**	**$25**	**$893**	**$1,111**
Other Investments[4]	-	-	267	267
Project Funding, net of fees[5]	-	-	(1,076)	(1,076)
Total Capital Expenditures and Growth Investments, net	**$193**	**$25**	**84**	**$302**

[1] Excludes $29 MM of insurance proceeds on maintenance capex including $5 MM at NRG Yield; [2] Includes cost-to-achieve spend of $6 MM; [3] Also includes International and BETM. Includes growth capital spend related to Carlsbad; [4] Includes investments and acquisitions; [5] Includes net debt proceeds, cash grants and third-party contributions

Generation Organizational Structure

NRG Energy, Inc. (30,047[1] MW)

Renewables (880 MW)

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

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

NRG Yield (2,888 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
- SPP Projects
- Sleeping Bear
- Taloga
- Tucson
- Univ. of Bridgeport
- Walnut Creek
- Wildorado

Gulf Coast (13,714 MW)

Texas (10,137 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

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

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 (9,573 MW)

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

LEGEND

- Separate Credit Facility (dotted green box)
- drop down to NRG Yield on March 27, 2017 (pink box)
- Equity Investments (underlined)

[1] Capacity controlled by NRG as of 12/31/2017, 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 12/31/2017

($ 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		4,845
Term loan due 2023		1,872
Tax exempt bonds due 2038-2045		465
Capital Lease		4
Total	**$**	**7,186**

Conventional Financings

Other non-recourse debt	$	6

Midwest Generation

Capacity Monetization/ Operating leases[2]	$	152

Carlsbad Energy

Term Loan	$	427

Agua Caliente

Project financing due 2037	$	818
Borrower 1 due 2038		89

Ivanpah

Promissory Note and Project financing due 2033 and 2038	$	1,145

Other Renewables Financings

Project financings	$	900

NRG Yield, Inc.

Senior convertible notes due 2019-2020	$	633

NRG Yield Operating LLC

Revolver $495 MM due 2019[3]	$	55
Senior Notes due 2024		500
Senior Notes due 2026		350

Conventional

Term loans due 2017 & 2023	$	1,030

Thermal

Senior secured notes due 2017-2025 and 2031	$	208

Renewable

Project financings[4]	$	3,138

Note: Debt balances exclude discounts and premiums
[1] $825 MM LC's issued and $1,711 MM Revolver available at NRG; [2] Excludes the present value of lease payments (9.1% discount rate) for Midwest Generation operating lease of $95 MM; this lease is guaranteed by NRG Energy, Inc.; [3] $74 MM of LC's were issued and $366 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)	12/31/2017	9/30/2017	6/30/2017	3/31/2017
Recourse Debt				
Term Loan Facility	$ 1,872	$ 1,876	$ 1,881	$ 1,886
Senior Notes	4,845	5,449	5,449	5,449
Tax Exempt Bonds	465	465	455	455
Revolver	-	-	-	125
Capital Lease	4	6	6	8
Recourse Debt and Capital Lease Subtotal	**$ 7,186**	**$ 7,796**	**$ 7,791**	**$ 7,923**
Non-Recourse Debt				
Total NRG Yield[1,2]	$ 5,914	$ 5,901	$ 5,983	$ 6,051
Renewables (including capital leases)[2]	2,952	2,854	2,811	2,661
Conventional	586	587	546	220
Non-Recourse Debt Subtotal	**$ 9,452**	**$ 9,342**	**$ 9,340**	**$ 8,932**
Total Debt	**$ 16,638**	**$ 17,138**	**$ 17,131**	**$ 16,855**

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

2017 Proceeds from Dropdowns, Asset Financings and Sales

($ millions)

Agua Caliente project level financing proceeds	$ 128
Utah Solar and 16% interest in Agua Caliente	130
TE Holdco (25%)	42
SPP and Other assets	71
DG Partnership	64
MN Wind Assets	37
Total Proceeds	**$472**

Appendix:
Reg. G Schedules

Reg. G: Full Year 2017 Free Cash Flow before Growth

($ millions)	QTD 12/31/2017	YTD 12/31/2017
Adjusted EBITDAR	**$ 503**	**$ 2,395**
Less: EME operating lease expense	(6)	(22)
Adjusted EBITDA	**$ 497**	**$ 2,373**
Interest payments	(208)	(851)
Income tax	(3)	(9)
Collateral / working capital / other[1]	295	(88) a
Cash Flow from Operations (continuing operations)	**$ 581**	**$ 1,425**
Reclassifying of net receipts (payments) for settlement of acquired derivatives that include financing elements	-	2
Gain on Sale	(3)	5
Return of capital from equity investments[2]	4	26
Cost-to-Achieve[3]	23	37
Cash contribution to GenOn pension plan[4]	-	13
Collateral[1]	(23)	159
Adjusted Cash Flow from Operations	**$ 582**	**$ 1,667**
Maintenance capital expenditures, net[5]	(39)	(164)
Environmental capital expenditures, net	-	(24)
Distributions to non-controlling interests	(47)	(175)
Consolidated Free Cash Flow before Growth	**$ 497**	**$ 1,304**
Less: FCFbG at Non-Guarantor Subsidiaries[6]	(114)	(407)
NRG-Level Free Cash Flow before Growth	**$ 383**	**$ 897**

a

Total Change in Working Capital & Other	
2017 Actuals (sum of a)	$154
Less: Adjustments	($48)
2017 Actuals Adj.	106
Original guidance (excl. GenOn)	(115)
Improvement	**$221**
Transformation Target	*$175*

[1] Reflects change in NRG's cash collateral balance as of 4Q2017 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 $29 MM; [6] Reflects impact from NRG Yield and other excluded project subsidiaries

Reg. G: 2018 Guidance

Appendix Table A-1: 2018 Guidance

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

($ millions)	**2018 Guidance**
Adjusted EBITDA	**$2,800 - $3,000**
Interest payments	(785)
Income tax	(40)
Working capital / other	40
Adjusted Cash Flow from Operations	**$2,015 - $2,215**
Maintenance capital expenditures, net	(210) - (240)
Environmental capital expenditures, net	(0) - (5)
Distributions to non-controlling interests[1]	(220) - (250)
Consolidated Free Cash Flow before Growth	**$1,550 - $1,750**
Less: FCFbG at Non-Guarantor Subsidiaries[2]	(380)
NRG-Level Free Cash Flow before Growth	**$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: Fourth 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	**(1,486)**	**(214)**	**(1,700)**	**506**	**(207)**	**(98)**	**(168)**	**(1,667)**
Plus:								
Interest expense, net	-	5	5	2	22	68	96	193
Income tax	-	-	-	-	(7)	57	(47)	3
Loss on debt extinguishment	-	-	-	-	-	1	49	50
Depreciation and amortization	63	27	90	31	51	88	7	267
ARO Expense	11	13	24	-	1	1	-	26
Contract amortization	6	1	7	-	-	17	1	25
Lease amortization	-	(2)	(2)	-	-	-	-	(2)
EBITDA	**(1,406)**	**(170)**	**(1,576)**	**539**	**(140)**	**134**	**(62)**	**(1,105)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	2	6	8	(7)	2	27	2	32
Acquisition-related transaction & integration costs	-	-	-	-	-	1	1	2
Reorganization costs	6	1	7	6	1	-	12	26
Legal Settlement	-	-	-	(1)	-	-	-	(1)
Deactivation costs	3	6	9	-	-	-	2	11
Gain on sale of business	-	(13)	(13)	-	5	-	(8)	(16)
Other non recurring charges	4	(7)	(3)	-	(4)	10	10	13
Impairments	1,267	196	1,463	8	130	32	(1)	1,632
Impairment losses on investments	69	5	74	-	1	-	4	79
Mark to market (MtM) (gains)/losses on economic hedges	100	35	135	(331)	19	-	1	(176)
Adjusted EBITDA	**45**	**59**	**104**	**214**	**14**	**204**	**(39)**	**497**

[1] Includes International, BETM and generation eliminations

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Appendix Table A-3: Fourth 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	**(671)**	**(103)**	**(774)**	**317**	**(223)**	**(115)**	**(96)**	**(891)**
Plus:								
Interest expense, net	-	1	1	-	17	67	91	176
Income tax	-	1	1	-	(6)	(26)	(39)	(70)
Loss on debt extinguishment	-	-	-	-	-	-	23	23
Depreciation and amortization	155	29	184	28	45	75	14	346
ARO Expense	3	2	5	-	1	1	1	8
Contract amortization	4	-	4	1	-	17	2	24
Lease amortization	-	(2)	(2)	-	-	-	-	(2)
EBITDA	**(509)**	**(72)**	**(581)**	**346**	**(166)**	**19**	**(4)**	**(386)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	(2)	8	6	-	44	7	(43)	14
Acquisition-related transaction & integration costs	-	-	-	-	-	1	-	1
Deactivation costs	-	2	2	-	-	-	1	3
Loss on sale of business	-	-	-	-	-	-	1	1
Other non-recurring charges	-	3	3	1	1	2	(2)	5
Impairments	368	36	404	1	28	185	19	637
Impairment losses on investments	-	-	-	-	106	-	15	121
Mark to market (MtM) (gains)/losses on economic hedges	239	44	283	(214)	6	-	-	75
Adjusted EBITDA	**96**	**21**	**117**	**134**	**19**	**214**	**(13)**	**471**

[1] Includes International, BETM and generation eliminations

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Appendix Table A-4: Full Year 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	**(1,427)**	**(71)**	**(1,498)**	**886**	**(266)**	**(23)**	**(647)**	**(1,548)**
Plus:								
Interest expense, net	1	26	27	5	97	303	445	877
Income tax	-	2	2	(9)	(20)	72	(37)	8
Loss on debt extinguishment	-	-	-	-	1	3	49	53
Depreciation and amortization	270	107	377	117	196	334	32	1,056
ARO Expense	22	22	44	1	2	4	(1)	50
Contract amortization	16	4	20	1	-	69	-	90
Lease amortization	-	(8)	(8)	-	-	-	-	(8)
EBITDA	**(1,118)**	**82**	**(1,036)**	**1,001**	**10**	**762**	**(159)**	**578**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	17	25	42	(17)	(12)	106	6	125
Acquisition-related transaction & integration costs	-	-	-	-	-	3	1	4
Reorganization costs	9	1	10	11	1	-	22	44
Legal Settlement	-	-	-	(1)	-	-	-	(1)
Deactivation costs	4	8	12	-	-	-	9	21
Gain on sale of assets	-	(20)	(20)	-	5	-	(1)	(16)
Other non-recurring charges	(21)	(2)	(23)	1	(17)	18	44	23
Impairments	1,309	195	1,504	7	154	44	-	1,709
Impairment losses on investments	69	5	74	-	-	-	5	79
Mark to market (MtM) (gains)/losses on economic hedges	(52)	24	(28)	(177)	12	-	-	(193)
Adjusted EBITDA	**217**	**318**	**535**	**825**	**153**	**933**	**(73)**	**2,373**

[1] Includes International, BETM and generation eliminations

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Appendix Table A-5: Full Year 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	**(920)**	**96**	**(824)**	**1,053**	**(330)**	**2**	**(884)**	**(983)**
Plus:								
Interest expense, net	1	24	25	-	97	283	481	886
Income tax	(2)	1	(1)	1	(20)	(1)	26	5
Loss on debt extinguishment	-	-	-	-	-	-	142	142
Depreciation and amortization	406	110	516	111	185	303	57	1,172
ARO Expense	11	4	15	-	2	3	1	21
Contract amortization	14	5	19	7	1	75	(3)	99
Lease amortization	-	(8)	(8)	-	-	-	-	(8)
EBITDA	**(490)**	**232**	**(258)**	**1,172**	**(65)**	**665**	**(180)**	**1,334**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	3	27	30	-	42	75	(41)	106
Acquisition-related transaction & integration costs	-	-	-	-	-	1	7	8
Deactivation costs	-	15	15	-	-	-	2	17
Loss on sale of business	-	-	-	1	-	-	79	80
Other non-recurring charges	19	(2)	17	2	9	6	23	57
Impairments	377	53	430	1	54	185	32	702
Impairment loss on investments	137	5	142	-	105	-	21	268
Mark to market (MtM) (gains)/losses on economic hedges	447	46	493	(365)	6	-	-	134
Adjusted EBITDA	**493**	**376**	**869**	**811**	**151**	**932**	**(57)**	**2,706**

[1] Includes International, BETM and generation eliminations

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Appendix Table A-6: Expected Full Year 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

($ millions)	NYLD / Other 2018 Guidance
Adjusted EBITDA	**1,355**
Interest payments	(360)
Collateral / working capital / other	(185)
Cash Flow from Operations	**810**
Maintenance capital expenditures, net	(40)
Environmental capital expenditures, net	-
Distributions to NRG	(180)
Distributions to non-controlling interests	(210)
Free Cash Flow before Growth	**380**

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

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

	2018 Adjusted EBITDA Guidance	
($ millions)	**Low**	**High**
GAAP Net Income [1]	410	610
Income tax	20	20
Interest Expense	785	785
Depreciation, Amortization, Contract Amortization and ARO Expense	1,180	1,180
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	135	135
Other Costs [2]	270	270
Adjusted EBITDA	**$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

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Appendix Table A-8: Expected Full Year 2018 Adjusted EBITDA Reconciliation for ROFO/ Renewable /Conventional
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	**2018 Pro-Forma** ROFO/ Renewable/ Convention
Net (loss)/income	**63**
Plus:	
Income tax	-
Interest expense, net	35
Depreciation, Amortization, Contract Amortization, and ARO Expense	120
EBITDA	**218**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-
Deactivation costs	3
Asset write-offs and impairments	
Other non-recurring charges	-
Mark to market (MtM) losses on economic hedges	3
Plus: Operating lease expense	22
Adjusted EBITDAR	**246**
Less: Operating lease expense	(22)
Adjusted EBITDA - Standalone	**225**

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Appendix Table A-9: Prior 8 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	4Q 2017
(Loss)/Income from Continuing Operations	**(57)**	**(163)**	**128**	**(892)**	**(170)**	**99**	**190**	**(1,667)**
Plus:								
Income tax	22	25	28	(70)	(5)	4	6	3
Interest expense, net	240	236	234	176	222	244	217	193
Loss on debt extinguishment	(11)	80	50	23	2	0	0	50
Depreciation, Amortization, Contract Amortization, and ARO Expense	300	290	370	374	287	287	299	316
EBITDA	**494**	**468**	**757**	**(389)**	**336**	**634**	**712**	**(1,105)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	34	32	27	14	18	47	28	32
Deactivation costs	8	5	2	3	1	4	7	11
Other non-recurring charges	166	160	12	768	13	59	35	1,735
Mark to market (MtM) losses on economic hedges	(61)	33	87	75	18	(59)	24	(176)
Adjusted EBITDA	**641**	**698**	**895**	**471**	**386**	**685**	**806**	**497**

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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 Divestitures Announced	Divestitures to be Completed
Net (loss)/income[1]	**200**	**5**
Plus:		
Income tax	25	(25)
Interest expense, net	326	45
Depreciation, Amortization, Contract Amortization, and ARO Expense	577	81
EBITDA	**1,128**	**106**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	77	(9)
Deactivation Costs and non-recurring charges	-	3
Adjusted EBITDA	**1,205**	**100**
Interest payments	(320)	(33)
Collateral / working capital / other	(57)	18
Cash Flow from Operations	**828**	**85**
Maintenance capital expenditures, net	(65)	(1)
Distributions to non-controlling interests	(173)	(34)
Free Cash Flow before Growth - Consolidated	**590**	**50**
Less: FCFbG at NRG Yield and Other Non-Guarantor Subsidiaries	(345)	(30)
Free Cash Flow before Growth – Residual	**245**	**20**

[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: 2017 Adjusted EBITDA Guidance

Appendix Table A-11: 2017 Adjusted EBITDA Guidance: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

	2017 Adjusted EBITDA Guidance	
($ millions)	**Low**	**High**
GAAP Net Income [1]	55	155
Income tax	10	10
Interest Expense	835	835
Depreciation, Amortization, Contract Amortization and ARO Expense	1,170	1,170
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	130	130
Other Costs [2]	200	200
Adjusted EBITDA	**$2,400**	**$2,500**

[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: 2017 FCFbG Guidance

Appendix Table A-12: 2017 FCFbG Guidance: The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

($ millions)	**2017 Guidance**
Adjusted EBITDA	**$2,400 - $2,500**
Interest payments	(835)
Income tax	(25)
Working capital / other	60
Adjusted Cash Flow from Operations	**$1,600 - $1,700**
Maintenance capital expenditures, net	(200) - (220)
Environmental capital expenditures, net	(25) - (35)
Distributions to non-controlling interests[1]	(180) - (190)
Consolidated Free Cash Flow before Growth	**$1,175 - $1,275**
Less: FCFbG at Non-Guarantor Subsidiaries[2]	(420)
NRG-Level Free Cash Flow before Growth	**$755 - $855**

[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: 2014-2015 Retail Adjusted EBITDA

Appendix Table A-13: 2014-2015 Retail Adjusted EBITDA Reconciliation: The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net income/(loss)

($ millions)	**2014**	**2015**
Net income/(loss)	**(24)**	**624**
Plus:		
Interest expense, net	2	1
Income tax	1	1
Depreciation, amortization, and ARO expense	134	133
Amortization of contracts	4	6
EBITDA	**117**	**765**
Acquisition-related transaction & integration costs	3	1
Reorganization costs	-	3
Other non recurring charges	5	(12)
Impairment losses	-	36
Mark- to- Market (MtM) losses/(gains) on economic hedges	507	-
Adjusted EBITDA	**632**	**793**

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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.

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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.