NRG Energy Inc.

Second Quarter 2018 Earnings Presentation

August 2, 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, cyberterrorism and inadequate cybersecurity, unanticipated outages at our generation facilities, adverse results in current and future litigation, failure to identify, execute or successfully implement acquisitions, repowerings or asset sales, our ability to implement value enhancing improvements to plant operations and companywide processes, our ability to implement and execute on our publicly announced transformation plan, including any cost savings, margin enhancement, asset sale, and net debt targets, our ability to proceed with projects under development or the inability to complete the construction of such projects on schedule or within budget, risks related to project siting, financing, construction, permitting, government approvals and the negotiation of project development agreements, our ability to progress development pipeline projects, the 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 August 2, 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 Second Quarter Results and Full Year Financial Outlook

**Executing on Transformation Plan Priorities;
On Track with 2018 and Full Plan Targets**

**Integrated Platform Performs Through Summer Volatility;
Continues to Provide Predictability**

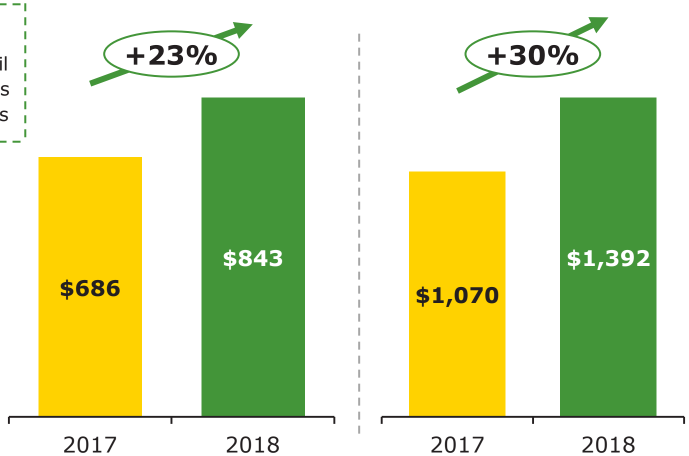
Q2 Results and Highlights

Results

Adjusted EBITDA ($ MM)

Second Quarter | **First Half of Year**

Drivers:
- ↑ Strong retail
- ↑ Power prices
- ↑ Cost savings



Maintaining 2018 Guidance:

$2,800 - $3,000 Adjusted EBITDA
$1,550 - $1,750 Free Cash Flow before Growth

Highlights

- ☑ Strong Q2 financial and operational results with $843 MM Adj. EBITDA; continued focus on safety
- ☑ Integrated platform benefiting from strong retail performance and higher wholesale prices
- ☑ Completed first $500 MM share buyback program at average realized price of $31.80/share; expect to launch second $500 MM program upon closing of NYLD/Renewables or South Central transaction
- ☑ Strong PJM Capacity auction results provide stability and visibility through mid-2022
- ☑ Consummated settlement and obtained releases from GenOn; GenOn plans to exit bankruptcy on 10/1/2018

2Q18 Results 23% Higher than 2Q17; Continued Execution of Key Priorities

Transformation Plan Update

Continued Progress on Plan Initiatives

Cost Savings and Margin Enhancement:

- ☑ $145 MM of cost savings in Q2; $225 MM in 1H18
- ☑ On track with margin enhancement for 2H18

Portfolio Optimization:

- ☑ ***New*:** Closed BETM: $70 MM
- ☑ ***New*:** Announcing the sale of NRG's 3.7% interest in Keystone and Conemaugh (to close in 2H18) and Spanish Town (transaction closed) for combined cash proceeds of $12 MM, sales previously targeted for 2019
- ☑ 2018 announced asset sales on track:
  - ☑ NYLD/Renewables: $1,375 MM
  - ☑ South Central: $1,000 MM
  - ☑ Carlsbad: $365 MM

Capital Allocation:

- ☑ On track to achieve 3.0x net debt/Adj. EBITDA in 2018

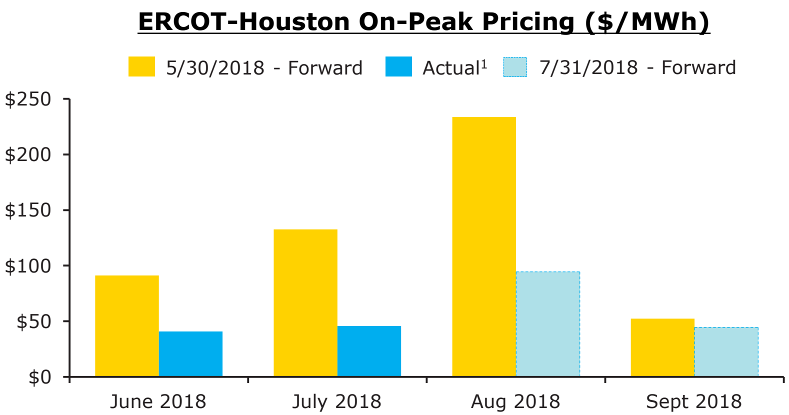
2018 Score Card as of 6/30/2018

($ millions)	YTD Realized	YTD % Achieved	2018 Target
Accretive & Recurring:			
Cost Savings	225	*45%*	500
Margin Enhancement	0	*0%*	30
Total EBITDA - Accretion	**$225**	***42%***	**$530**
Maintenance Capex	18	*60%*	30
Total Recurring FCFbG - Accretion	**$243**	***43%***	**$560**
Non-Recurring:			
Working Capital Improvement	76	*89%*	85
Cost to Achieve Total Transformation Plan	(69)	-	(246)
Total Non-Recurring	**$7**	**-**	**($161)**
Annual Cash Accretion	**$250**	***63%***	**$399**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**~$577**	***~79%***	**~$726**

On Track to Achieve 2018 and Full Transformation Plan Targets

Summer Update: Integrated Platform Positioning

Strong Reliability Impacting Spot Pricing



(MWs)	ERCOT SARA[2] Expectation	Record Peak Day (July 19th)
Record Demand: *Peak Load*	72,756	73,259
Strong Generation Reliability: *Outages*	4,349	3,300
Wind Meets Expectations: *Wind Output*	4,194	4,229

Integrated Platform Well-Positioned Through Summer

Retail Business Prepared for Summer Volatility
- Priced-load fully hedged, purchased options for high load/price scenario
- Leadership in customer experience with outreach and assistance with high bills
- Opportunity to acquire customers at value

Strong Generation Position Ahead of Summer
- Expanded spring outage work and purchased forced outage insurance
- Strong fleet reliability and in-the-money availability
- Maintaining long position to manage retail load

Disciplined Execution of Long-Term Hedges
- Capitalizing on opportunities to lock in hedges in summer 2019 and 2020 at attractive levels
- Increasing earnings predictability

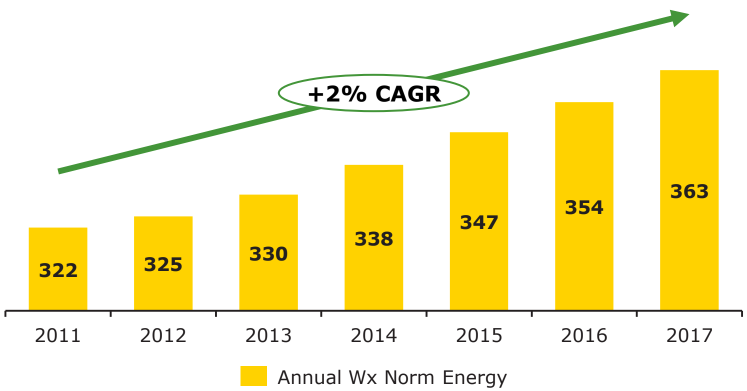
ERCOT Power Grid Remains Tight Through Summer; NRG Focused on Fleet Reliability and Platform Performance

[1] Real time prices; [2] Seasonal Assessment and Resource Adequacy

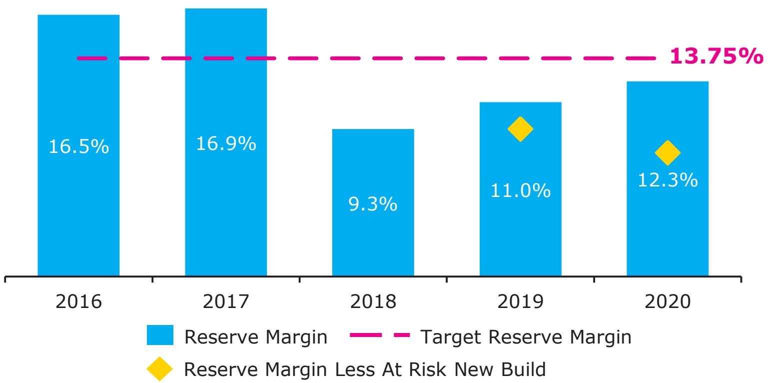
Market Outlook: ERCOT

Strong Fundamentals Drive Tight Reserve Margins…

Steady Demand Growth[1] (TWh)



Reserve Margin Under Continued Pressure[2]



…Creating Compelling Opportunities for NRG Integrated Platform

Scalable Retail Platform:

- Steady load growth drives continued retail demand
- Scalable customer acquisition and retention engine
- Strong risk management capabilities through integration with generation business

Reliable Generation Fleet:

- Opportunistically lock in hedges given rise in forward prices
- Maintain long generation position to cover peaks in retail load
- Reliable, environmentally compliant fleet located near load pockets

Retail and Generation Well-Positioned for Long-Term Success in Strong ERCOT Market

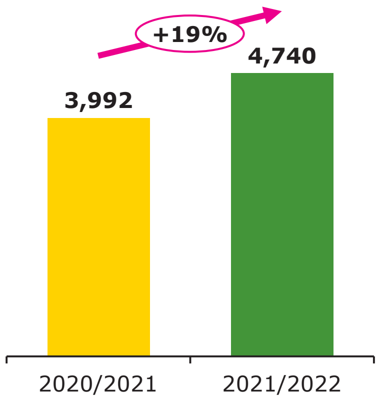
[1] ERCOT, NOAA, and internal estimates; [2] 2016 reserve margin from the Dec 2015 CDR, 2017 reserve margin from the Dec 2016 CDR, 2018 reserve margin from the Dec 2017 CDR, 2019 and 2020 reserve margins from the May 2018 CDR, Reserve Margin less At Risk New Build excludes 50% of new renewables and excludes the following at risk thermal new builds: Halyard Henderson, Halyard Wharton, Pine Crest Energy Center

Market Outlook: East

NRG Clears More Megawatts at Higher Prices

PJM 21/22 Capacity Auction

NRG Cleared Capacity[1] (MW)



Weighted Avg. Price[1] ($/MW-day)

- NRG auction revenues 22% higher
- Disciplined bidding drives strong 21/22 auction results in PJM
- New build and uprates slowed with 1.4 GW cleared compared to 2.8 GW prior year

Several Ongoing Regulatory Changes Aim to Improve Competitive Markets

Type	Description
PJM Capacity	• FERC concluded that PJM's existing tariff is not just and reasonable because it does not "protect the integrity of competition in the wholesale capacity market" • Briefing in late August, reply briefs in September, order expected in January 2019
PJM Energy	• Price formation reform would allow inflexible units to set price resulting in increased prices • Fast-Start proceeding action expected in September 2018 • Single sync reserve market and ORDC[2] improvements expected in early 2019; 30-minute real-time and fully-baked ORDC[2] expected later in 2019
ISO-NE	• FERC rejected waiver request to retain Mystic for fuel security reasons • FERC directed ISO-NE to develop a permanent fix that would price all fuel security units in the market

Disciplined Bidding and Pro-Market Policy Drive Strong Outlook for East

[1] See slide 28; [2] Operating Reserve Demand Curve

Financial Update

Financial Summary

($ millions)	6/30/2018 Three Months Ended	6/30/2018 Six Months Ended	Maintaining Full Year Guidance
Generation & Renewables[1]	$242	$414	$950 – $1,050
Retail	298	486	900 – 1,000
NRG Yield	303	492	950
Adjusted EBITDA	**$843**	**$1,392**	**$2,800 - $3,000**
Consolidated Free Cash Flow before Growth (FCFbG)	**$259**	**$366**	**$1,550 - $1,750**

- Strong Q2 results from improved wholesale power prices and retail volumes and continued execution on cost reductions
- Completed $500 MM of the $1 Bn share buyback program; 15.7 MM shares repurchased at average price of $31.80/share
- Issued $575 MM of convertible notes; will repurchase equivalent amount of senior unsecured notes
  - Expected to reduce annual interest by ~$20 MM
  - Repurchased $89 MM of senior unsecured notes to date, and provided notice to purchase $486 MM of 2022 notes
- Closed on settlement with GenOn including repayment of intercompany revolver

[1] Includes Corporate segment

Pro Forma Financial Summary Update

($ millions)	Prior Pro Forma[2]	Ivanpah Deconsolidation / XOOM Energy	Revised Pro Forma[2,3]
Generation & Renewables[1]	~$660	($45) A	~$605
Retail	~$950	$45 B	~$995
NRG Yield	–		–
Adjusted EBITDA	**~$1,600**	–	**~$1,600**
Consolidated Free Cash Flow before Growth (FCFbG)	**~$1,000**	$45	**~$1,050**

Update from 1Q18

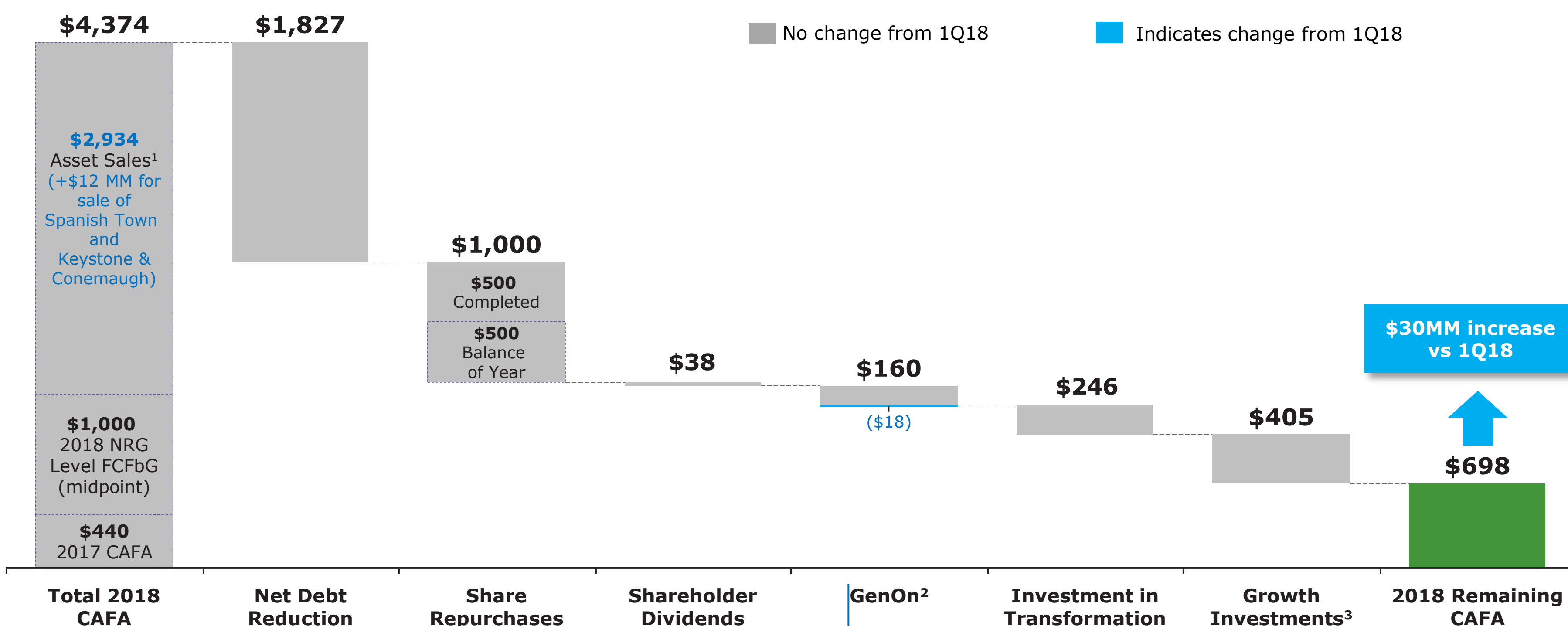
	2018 Includes	2020 Run Rate	Incremental Beyond 2018
Cost Savings	$500	$590	$90
Margin Enhancements	30	215	185
Incremental Impact to Adjusted EBITDA			$275

- Revised annualized pro forma Adj. EBITDA / FCFbG to reflect deconsolidation of Ivanpah and acquisition of XOOM Energy
- Deconsolidated Ivanpah following restructuring of project debt on 5/9/2018:
  - Pro forma Adj. EBITDA contribution of ~$55 MM going forward (NRG owns ~55% of project)
  - A Partner's ~45% share (~$45 MM) deconsolidation impact
- XOOM Energy acquisition – closed on 6/1/2018:
  - B Annualized Adj. EBITDA impact of $45 MM

[1] Includes Corporate segment; [2] Pro Forma financials assuming asset sales, acquisitions and deconsolidations occurred on 1/1/2018; [3] See appendix slide 31 for 2018 full year guidance to Pro Forma

2018 NRG-Level Capital Allocation

($ millions)



Debt Reduction	$ 640
Term Loan Amortization	19
Midwest Gen Debt Amortization[4]	103
Cash Reserve to achieve 3.0x	1,065

✓ Settlement	$ 261
✓ Intercompany Revolver	(125)
✓ Other Settlement Credits	28
Pension	14
✓ **Interest on Intercompany Revolver**	**(12)**
✓ **Other Balances due to NRG**	**(6)**

✓ Settled as part of July payment; see Appendix slide 32 for details of payment

[1] See appendix slide 39 for list of announced asset sales; includes transaction fees of $60 MM; [2] See Appendix slide 32 for further details; [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

Corporate Credit Profile

$ millions	2018 Pro-Forma	MWG	Transform. Plan	2020 Pro-Forma
Corporate Debt	**$7,176[1]**			**$6,526**
2018 Term Loan Amortization	(10)			(38)
Additional Debt Reduction (2018)	(640)			--
Pro Forma Corporate Debt	**$6,526**			**$6,488**
Cash & Cash Equivalents @ NRG-Level/Min Cash	(500)			(500)
Cash Reserve to meet 3.0x target	(1,065)			C --
Pro Forma Corporate Net Debt	**~$4,960**			**~$5,990**
Pro Forma Adj. EBITDA	**$1,600[2]**	**--**	A **$275**	**$1,875**
Less: Ivanpah & Midwest Gen Adj. EBITDA	(180)	B 125		(55)
Add: Ivanpah & Midwest Gen Cash Distributions to NRG	65	(45)		20
Other Adjustments[3]	150			150
Total Recourse Adj. EBITDA	**$1,635**	**Impact of 2018 Debt Reduction**	**Impact of Convertible Notes**	**$1,990**
Less: Corporate Interest Payments[4]	(400)	(40)	(20)	(340)
Less: Corporate Income Taxes[4]	(40)			(40)
Add: Working Capital / Other Adjustments	5			5
Total Corporate Adj. CFO[4]	**$1,200**			**$1,615**
Corporate Net Debt / Corporate Adj. EBITDA	**3.0x**			**3.0x**
Adj. CFO / Corporate Net Debt	**24.2%**			**27.0%**
(Corporate Adj. CFO + Corporate Interest) / Corporate Interest	**4.0x**			**5.8x**

A $275 MM incremental T-Plan EBITDA beyond 2018

B Full contribution of MWG EBITDA post-2019[4]

...Drives...

C Full release of 2018 cash reserve while maintaining 3.0x corporate credit ratio

Solely reflects adjustment for Ivanpah

Credit Metrics Significantly Better than Current BB-/Ba3 Credit Rating

[1] 2018 reflects balance at 6/30/2018 (includes NRG Energy, Inc. term loan facility, senior notes, revolver, capital leases and tax exempt bonds) less (i) $26 MM revolver repaid in July as part of GenOn settlement and (ii) remaining $531 MM of debt buybacks ($44 MM completed in Q2) to offset convertible debt issuance; [2] Annualized pro-forma reflects deconsolidation of Ivanpah and acquisition of XOOM Energy – see slide 31 for details; [3] Reflects non-cash expenses (i.e. nuclear amortization, equity compensation amortization, and bad debt expense) that are included in Adjusted EBITDA; [4] Reflects 2018 Consolidated Guidance (see Reg. G A-1) less Assets Divestitures Announced and Divestitures to be Completed (see Reg. G A-9); interest also adjusted for Ivanpah deconsolidation impact of ~$30 MM

Closing Remarks

2018 Priorities

- ☐ **Deliver on Financial and Operational Objectives**
  - ☑ Maintaining full year guidance ranges
  - ☑ Strong year-to-date financial, operational and safety performance
  - ☐ Execute $1 Bn share repurchase program
    - ☑ $500 MM completed in first half of 2018
    - ☐ Complete second $500 MM buyback by end of 2018

- ☐ **Execute on NRG Transformation Plan Objectives**
  - ☐ $500 MM of EBITDA-accretive cost savings in 2018
  - ☐ $30 MM of EBITDA-accretive margin enhancement in 2018
  - ☐ Achieve 3.0x Net Debt / Adjusted EBITDA by end of 2018

- ☐ **Complete Asset Sales, Dispositions, and Acquisitions**
  - ☑ Closed drop down in 1Q18 of Buckthorn Solar to NRG Yield
  - ☑ ***New*:** Closed on acquisition of XOOM Energy
  - ☑ ***New*:** Closed on sale of BETM, Canal 3 and Spanish Town
  - ☐ ***New*:** Expect to close on sales of Keystone and Conemaugh in 2018
  - ☐ NRG Yield / Renewables / Carlsbad expected to close in second half of 2018
  - ☐ South Central expected to close in second half of 2018
  - ☐ GenOn plans to exit Bankruptcy on 10/1/2018

Appendix

Transformation Plan Score Card

2018 Progress as of 6/30/2018

($ millions)	YTD Realized	YTD % Achieved	2018 Target
Accretive & Recurring:			
Cost Savings	225	*45%*	500
Margin Enhancement	0	*0%*	30
Total EBITDA - Accretion	**$225**	***42%***	**$530**
Maintenance Capex	18	*60%*	30
Total Recurring FCFbG - Accretion	**$243**	***43%***	**$560**
Non-Recurring:			
Working Capital Improvement	76	*89%*	85
Cost to Achieve Total Transformation Plan	(69)	-	(246)
Total Non-Recurring	**$7**	**-**	**($161)**
Annual Cash Accretion	**$250**	***63%***	**$399**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**~$577**	**~79%**	**~$726**

Transformation Plan Targets

($ millions)	2017	2017 Realized	2018	2019	2020 / Run Rate
Accretive & Recurring:					
Cost Savings	65	150	500	590	590
Margin Enhancement*	0	-	30	135	215
Total EBITDA - Accretion	**$65**	**$150**	**$530**	**$725**	**$805**
Maintenance Capex*	0	-	30	50	50
Total Recurring FCFbG Accretion	**$65**	**$150**	**$560**	**$775**	**$855**
Non-Recurring:[1]					
Working Capital Improvement	175	221	85	64	--
Cost to Achieve Total Transformation Plan	(115)	(44)	(246)	--	--
Total Non-Recurring	**$60**	**$177**	**($161)**	**$64**	**--**
Annual Cash Accretion	**$125**	**$327**	**$399**	**$839**	**$855**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$125**	**~$327**	**$726**	**$1,565**	**$2,420**

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

[1] 2018 Cost to Achieve target and 2019 working capital improvement target updated from original targets due to shifting of targets in forward years due to achievement levels in 2017; total targets did not change

Appendix: Operations

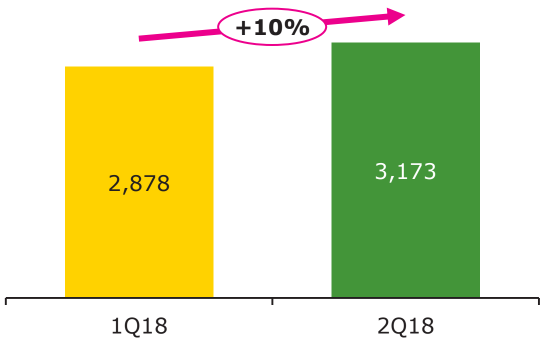
Retail: Operational Metrics

Q2 Highlights

- Delivered $298 MM in Adjusted EBITDA, $94 MM higher than 2Q17
- Closed XOOM Energy transaction on June 1st
- Continued operational efficiencies
- Reliant earned a 5-star rating and ranked #1 on Texas Electricity Ratings and Green Mountain rated Most Trusted Brand by MSI Cogent

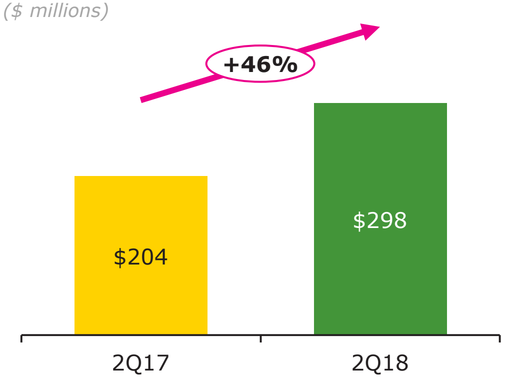
Growth in Q2 Mass Customer Count

Mass Recurring Customers[1] (000s)



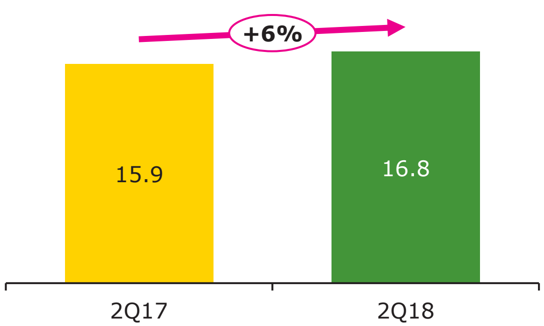
Strong Q2 EBITDA Earnings

Adjusted EBITDA ($ millions)



Higher Q2 Volumes

Delivered TWh

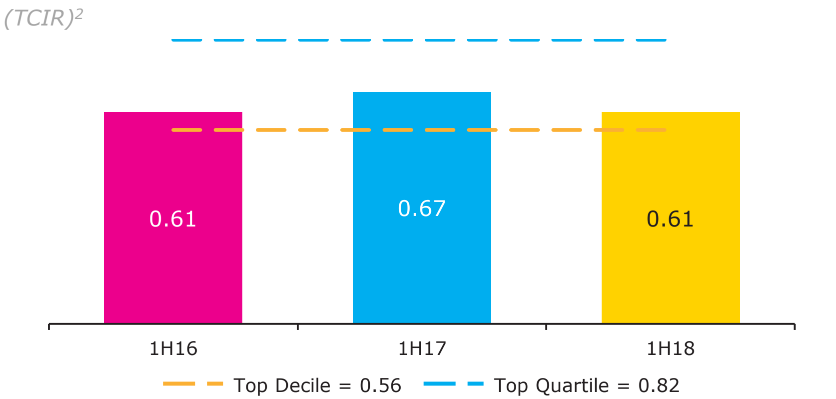


Delivered Another Strong Quarter and Successfully Closed XOOM Energy

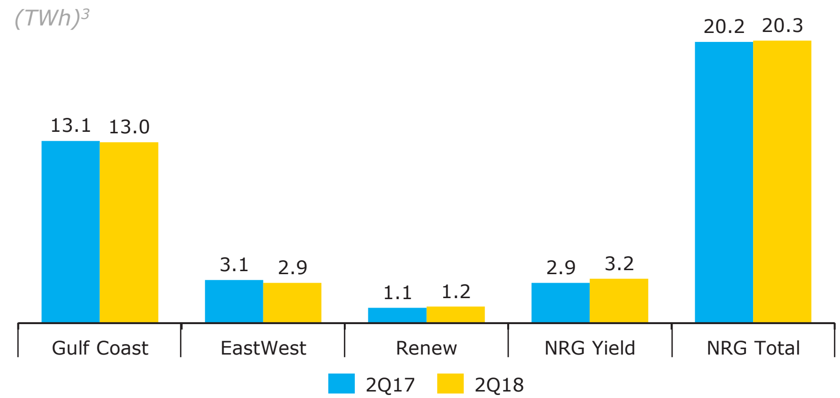
[1] Mass recurring customer count includes customers that subscribe to one or more recurring services, such as electricity and natural gas; excludes C&I customers

Generation: Operational Metrics

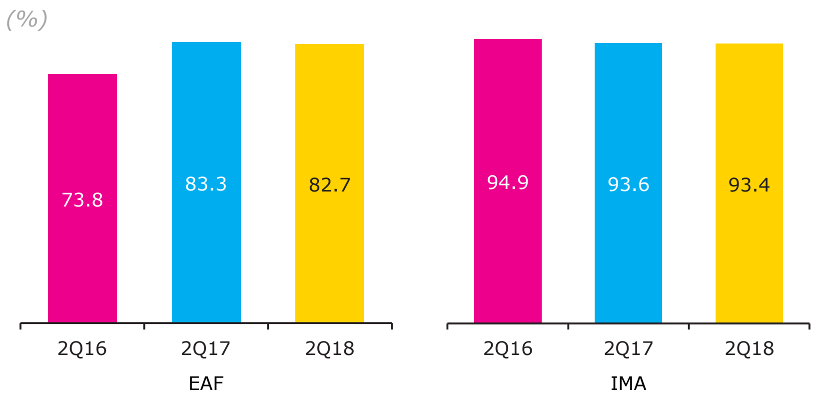
Safety[1]



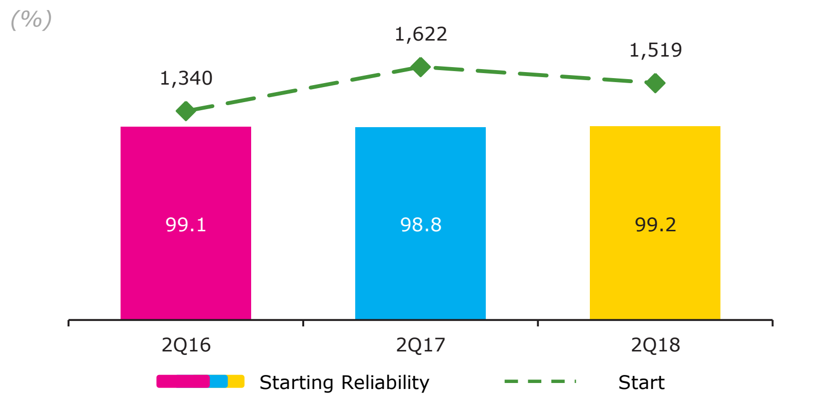
Production



Baseload Equivalent Availability Factor (EAF) and In-the-Money Availability (IMA)



Gas and Oil Starts and Reliability

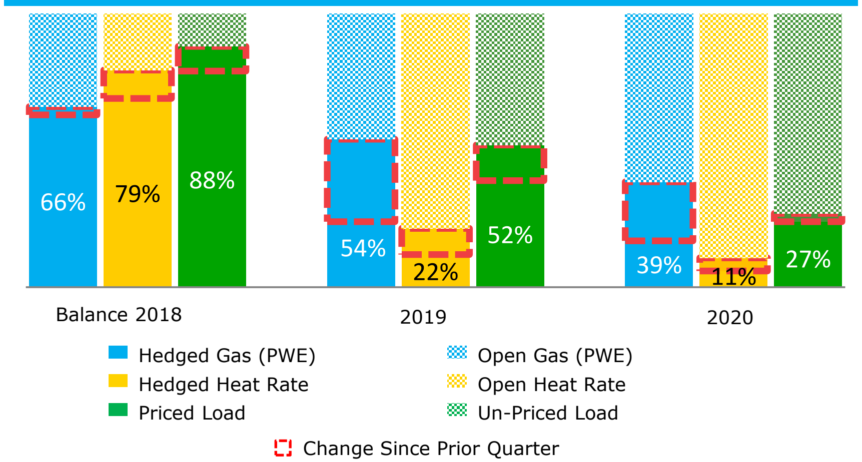


Strong In-the-Money Availability with Consistent Generation

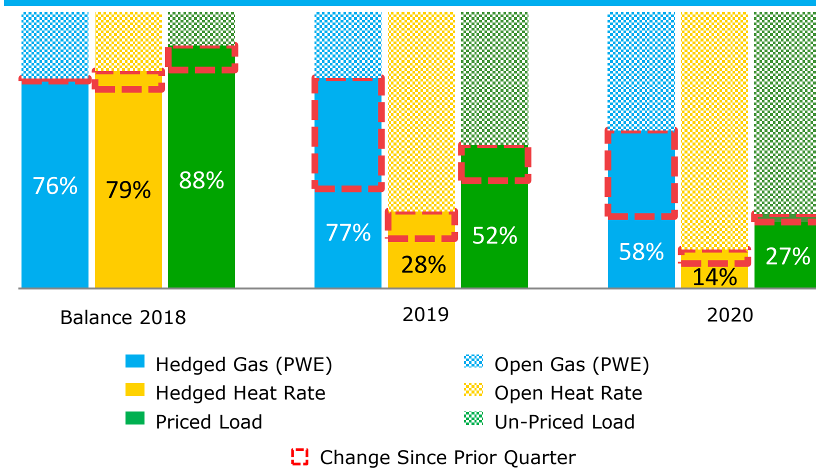
[1] Excludes Goal Zero, NRG Home Services and NRG Home Solar; top decile and top quartile based on Edison Electric Institute 2016 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation; excludes line losses, station service, and other items. Generation data presented above consistent with US GAAP accounting. Previous reports were pro-forma for acquisitions in prior periods

Pro Forma Portfolio[1] Managing Commodity Price Risk

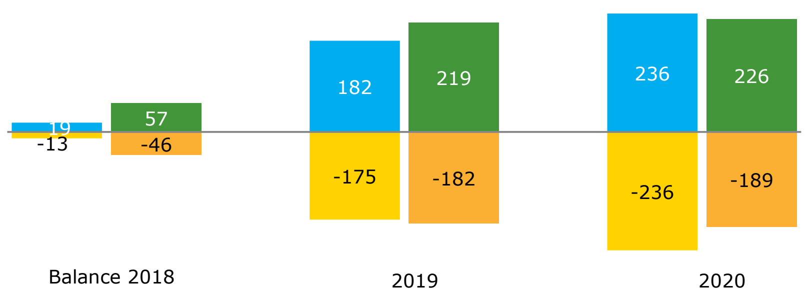
Total Portfolio Generation and Retail Hedge Position[1,2]



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



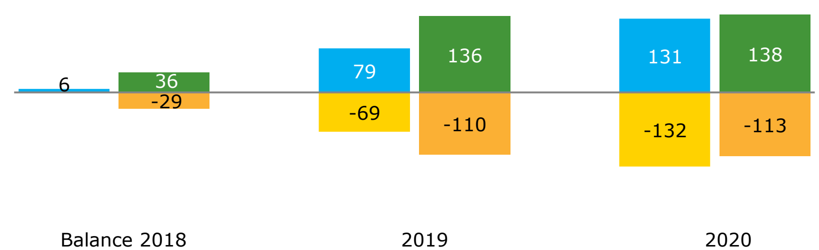
Total Portfolio Sensitivity to Gas Price and Heat Rate[1,3]



	Balance 2018	2019	2020
Henry Hub Gas as of 6/29	2.96	2.80	2.68

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]



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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 6/29/2018, includes TEXAS, PJM, NY, NE, CAISO & Cottonwood, excludes GenOn, MISO, Yield & Renew; Balance 2018 reflects July through December; [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 104%, 43%, and 20% for 2018, 2019, and 2020, respectively

2Q18 Hedge Disclosure: Coal and Nuclear Operations

Coal & Nuclear Portfolio [1]

		Texas			East		
		Balance 2018	2019	2020	Balance 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]	4,190	3,867	3,781	1,507	1,153	866
	Total Coal and Nuclear Sales (GWh)[4]	13,239	24,010	19,629	5,789	9,340	3,757
	Percentage Coal and Nuclear Capacity Sold Forward[5]	72%	71%	59%	87%	92%	49%
	Total Forward Hedged Revenues [6]	$562	$1,234	$828	$179	$263	$107
	Weighted Average Hedged Price ($ per MWh)[6]	$42.47	$51.41	$42.17	$30.86	$28.12	$28.38
	Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$2.04	$2.77	$2.67	$2.82	$2.82	$2.69
Gross Margin Sensitivities $ in MM	Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	($18)	$13	$47	$25	$65	$84
	Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$18	($37)	($84)	($17)	($32)	($48)
	Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$19	$79	$90	$17	$56	$49
	Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	($14)	($68)	($78)	($15)	($42)	($35)

[1] Portfolio as of 6/29/2018. Includes TEXAS and PJM; Excludes MISO. Balance 2018 reflects July through December
[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 6/29/2018 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 6/29/2018 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 2017 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 forward power and natural gas equivalent coal and nuclear sales

Commodity Prices

Forward Prices[1]	2018[2]	2019	2020	Annual Average for 2018-2020
NG Henry Hub ($/mmBtu)	$2.96	$2.80	$2.68	$2.81
PRB 8800 ($/Ton)	$12.40	$12.35	$12.30	$12.35
ERCOT Houston Onpeak ($/MWh)	$55.72	$45.40	$41.45	$47.52
ERCOT Houston Offpeak ($/MWh)	$27.61	$22.70	$20.79	$23.70
ERCOT Houston RTC ($/MWh)	$40.54	$33.28	$30.46	$34.76
PJM West Onpeak ($/MWh)	$37.04	$36.35	$35.19	$36.19
PJM West Offpeak ($/MWh)	$26.48	$26.99	$26.00	$26.49
PJM West RTC ($/MWh)	$31.34	$31.35	$30.30	$30.99

[1] Prices as of 6/29/2018; [2] Represents July through December months

Fuel Statistics

	Q2		1H	
Domestic[1]	**2018**	**2017**	**2018**	**2017**
Coal Consumed (mm Tons)	5.7	6.1	10.3	11.3
PRB Blend	**100%**	**94%**	**99%**	**94%**
East	98%	99%	97%	98%
Gulf Coast	100%	92%	100%	93%
Bituminous	**0%**	**0%**	**1%**	**0%**
East	2%	1%	3%	2%
Lignite	**0%**	**6%**	**0%**	**6%**
Gulf Coast	0%	8%	0%	7%
Cost of Coal ($/Ton)	**$ 31.95**	**$ 32.21**	**$ 32.14**	**$ 32.33**
Cost of Coal ($/mmBtu)	**$ 1.88**	**$ 1.89**	**$ 1.88**	**$ 1.90**
Cost of Gas ($/mmBtu)	**$ 2.75**	**$ 3.15**	**$ 3.03**	**$ 3.15**

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

Q2 2018 Generation & Operational Performance Metrics

(MWh 000's)	2018 Generation[1]	2017 Generation[1]	MWh Change	% Change	2018 EAF[2]	2018 NCF[3]	2017 EAF[2]	2017 NCF[3]
Gulf Coast	12,959	13,101	(141)	(1%)	85%	43%	86%	43%
East/West	2,902	3,079	(176)	(6%)	82%	12%	78%	12%
Renewables	1,211	1,059	152	14%	99%	39%	98%	38%
NRG Yield[4]	3,164	2,863	301	11%	97%	26%	96%	24%
Total	**20,237**	**20,101**	**136**	**1%**	**86%**	**29%**	**85%**	**29%**
Gulf Coast – Texas Nuclear	2,136	2,098	38	2%	85%	84%	83%	82%
Gulf Coast – Texas Coal	6,555	6,473	82	1%	91%	72%	90%	71%
Gulf Coast – South Central Coal	695	1,004	(309)	(31%)	74%	35%	68%	50%
East Coal	1,829	2,141	(312)	(15%)	74%	26%	79%	30%
Baseload	**11,216**	**11,717**	**(501)**	**(4%)**	**83%**	**54%**	**83%**	**56%**
Renewables Solar	606	527	79	15%	100%	33%	98%	39%
Renewables Wind	605	532	73	14%	99%	42%	99%	37%
NRG Yield Solar	458	403	55	14%	99%	40%	99%	39%
NRG Yield Wind	1,850	1,709	141	8%	98%	41%	97%	38%
Intermittent	**3,519**	**3,171**	**348**	**11%**	**98%**	**40%**	**98%**	**38%**
East Oil	59	58	1	2%	78%	1%	76%	1%
Gulf Coast – Texas Gas	1,156	1,517	(361)	(24%)	78%	11%	85%	14%
Gulf Coast – South Central Gas	2,417	2,008	409	20%	94%	42%	89%	35%
East Gas	336	338	(3)	(1%)	89%	6%	72%	6%
West Gas	678	541	137	25%	94%	17%	88%	13%
NRG Yield Conventional	367	313	54	17%	97%	9%	94%	7%
NRG Yield Thermal[4]	490	438	52	12%	83%	7%	89%	4%
Intermediate / Peaking	**5,502**	**5,213**	**289**	**6%**	**86%**	**13%**	**83%**	**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

1H 2018 Generation & Operational Performance Metrics

(MWh 000's)	2018 Generation[1]	2017 Generation[1]	MWh Change	% Change	2018 EAF[2]	2018 NCF[3]	2017 EAF[2]	2017 NCF[3]
Gulf Coast	23,146	23,790	(644)	(3%)	84%	39%	86%	39%
East/West	5,464	6,096	(632)	(10%)	84%	11%	84%	27%
Renewables	2,227	1,974	252	13%	99%	38%	99%	36%
NRG Yield[4]	5,855	5,267	588	11%	95%	23%	94%	22%
Total	**36,691**	**37,127**	**(436)**	**(1%)**	**86%**	**26%**	**87%**	**32%**
Gulf Coast – Texas Nuclear	4,451	4,418	33	1%	91%	87%	88%	86%
Gulf Coast – Texas Coal	11,162	11,488	(326)	(3%)	83%	62%	92%	63%
Gulf Coast – South Central Coal	1,499	1,969	(470)	(24%)	74%	38%	74%	49%
East Coal	3,662	4,444	(782)	(18%)	79%	26%	85%	81%
Baseload	**20,775**	**22,319**	**(1,544)**	**(7%)**	**82%**	**50%**	**87%**	**71%**
Renewables Solar	1,011	838	173	21%	100%	29%	99%	40%
Renewables Wind	1,215	1,136	79	7%	98%	42%	99%	35%
NRG Yield Solar	705	631	74	12%	99%	32%	99%	30%
NRG Yield Wind	3,219	3,158	61	2%	98%	36%	98%	38%
Intermittent	**6,151**	**5,763**	**387**	**7%**	**98%**	**36%**	**98%**	**36%**
East Oil	233	87	146	168%	86%	1%	85%	1%
Gulf Coast – Texas Gas	1,689	1,904	(214)	(11%)	81%	8%	81%	8%
Gulf Coast – South Central Gas	4,344	4,011	333	8%	92%	38%	90%	35%
East Gas	452	512	(60)	(12%)	86%	4%	81%	4%
West Gas	1,116	1,053	64	6%	85%	14%	86%	13%
NRG Yield Conventional	805	455	349	77%	91%	9%	89%	5%
NRG Yield Thermal[4]	1,127	1,023	103	10%	90%	6%	94%	4%
Intermediate / Peaking	**9,766**	**9,045**	**721**	**8%**	**86%**	**11%**	**85%**	**10%**

[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

Capacity Clears: NRG Standalone

Capacity Revenue by Calendar Year[1] ($ MM)

Market	2018	2019	2020
PJM	$312	$321	$286
NYISO	$126	$57	$17
NE-ISO	$157	$149	$110

NYISO 2018, 2019 & 2020 contains MWs that will be either bid into upcoming auctions or sold bilaterally

Market	Region	Planning Year	Average Price ($/kW-Month)	MWs Cleared	Estimated Qualified Capacity[2]
ISO-NE	Connecticut	2018-2019	$9.55	1,535	1,535
		2019-2020	$7.03	1,529	1,529
		2020-2021	$5.30	1,529	1,529
		2021-2022	$4.63	1,529	1,529
NYISO[3]		2018	$4.33	2,422	2,816
		2019	$3.64	1,306	2,820
		2020	$4.72	305	2,820
		2021	-	-	2,820

Assumptions:

- ISO-NE and NYISO data as of 6/29/2018
- Excludes NRG Yield Assets

[1] 2018 values exclude non-recurring CAISO payments; [2] Capacity that can be bid in a capacity auction; estimated as of 6/29/2018 and is subject to change; [3] NYISO - NYC estimated qualified capacity is 1.3 GW; NYISO - Central estimated qualified capacity is 1.6 GW

PJM Capacity Clears

Capacity Revenue by Calendar Year ($ MM)

Market	2018	2019	2020	2021
PJM	$312	$321	$286	$303

Capacity Revenue by Delivery Year ($ MM)

Market	18/19	19/20	20/21	21/22
PJM	$339	$309	$268	$328

			Base Product		Capacity Performance Product	
Market	**Region**	**Planning Year**	**Average Price ($/MW-Day)**	**MWs Cleared**	**Average Price ($/MW-Day)**	**MWs Cleared**
PJM	ComEd	2018-2019	$25.58	221	$215.00	3,509
		2019-2020	$182.77	65	$202.77	3,738
		2020-2021			$188.12	3,315
		2021-2022			$195.55	3,995
PJM	MAAC	2018-2019	$149.98	1	$150.70	122
		2019-2020	$80.00	1	$91.87	126
		2020-2021			$86.04	91
		2021-2022			$140.00	121
PJM	DPL South	2018-2019	$210.63	98	$217.08	481
		2019-2020	NA	NA	$119.77	481
		2020-2021			$187.87	519
		2021-2022			$165.73	552
PJM	PEPCO	2018-2019	NA	NA	$229.10	46
		2019-2020	NA	NA	$100.00	66
		2020-2021			$86.04	67
		2021-2022			$140.00	72
PJM	Net Total	2018-2019	$82.68	320	$217.05	4,157
		2019-2020	$181.51	65	$189.03	4,410
		2020-2021			$184.04	3,992
		2021-2022			$189.81	4,740

Assumptions:

- PJM Data as of 5/23/2018
- Pro forma for announced business and asset sales
- Represents merchant wholesale generation

PJM Asset List: Merchant Wholesale Generation

Net Generating Capacity by LDA[1]

ComEd (4,336 MW, Net)				
Name	**Location**	**Capacity**	**Entity**	**Ownership %**
Fisk	Chicago, IL	172	NRG	100%
Joliet	Joliet, IL	1,326	NRG	100%
Powerton	Pekin, IL	1,538	NRG	100%
Waukegan	Waukegan, IL	790	NRG	100%
Will County	Romeoville, IL	510	NRG	100%

DPL (593 MW, Net)				
Name	**Location**	**Capacity**	**Entity**	**Ownership %**
Indian River	Millsboro, DE	426	NRG	100%
Vienna	Vienna, MD	167	NRG	100%

MAAC (126 MW, Net)				
Name	**Location**	**Capacity**	**Entity**	**Ownership %**
Conemaugh	New Florence, PA	63	NRG	3.72%
Keystone	Shelocta, PA	63	NRG	3.70%

PEPCO (78 MW, Net)				
Name	**Location**	**Capacity**	**Entity**	**Ownership %**
NRG Chalk Point CT	Prince Georges County, MD	78	NRG	100%

[1] Load Delivery Area

Appendix: Finance

Pro Forma Financial Summary Update

($ millions)	Full Year Guidance	Full Year Impact: Asset Sales Announced[2]	Full Year Impact: Asset sales To be Completed[2]	Prior Pro Forma	Ivanpah Deconsolidation / XOOM	Revised Pro Forma
Generation & Renewables[1]	$950 – $1,050	($255)	($100)	~$650	($45)	~$605
Retail	900 – 1,000	–	–	~$950	$45	~995
NRG Yield	950	(950)	–	-	-	–
Adjusted EBITDA	**$2,800 - $3,000**	($1,205)	($100)	~$1,600	–	**~$1,600**
Consolidated Free Cash Flow before Growth (FCFbG)	**$1,550 - $1,750**	($590)	($50)	~$1,000	$45	**~$1,050**

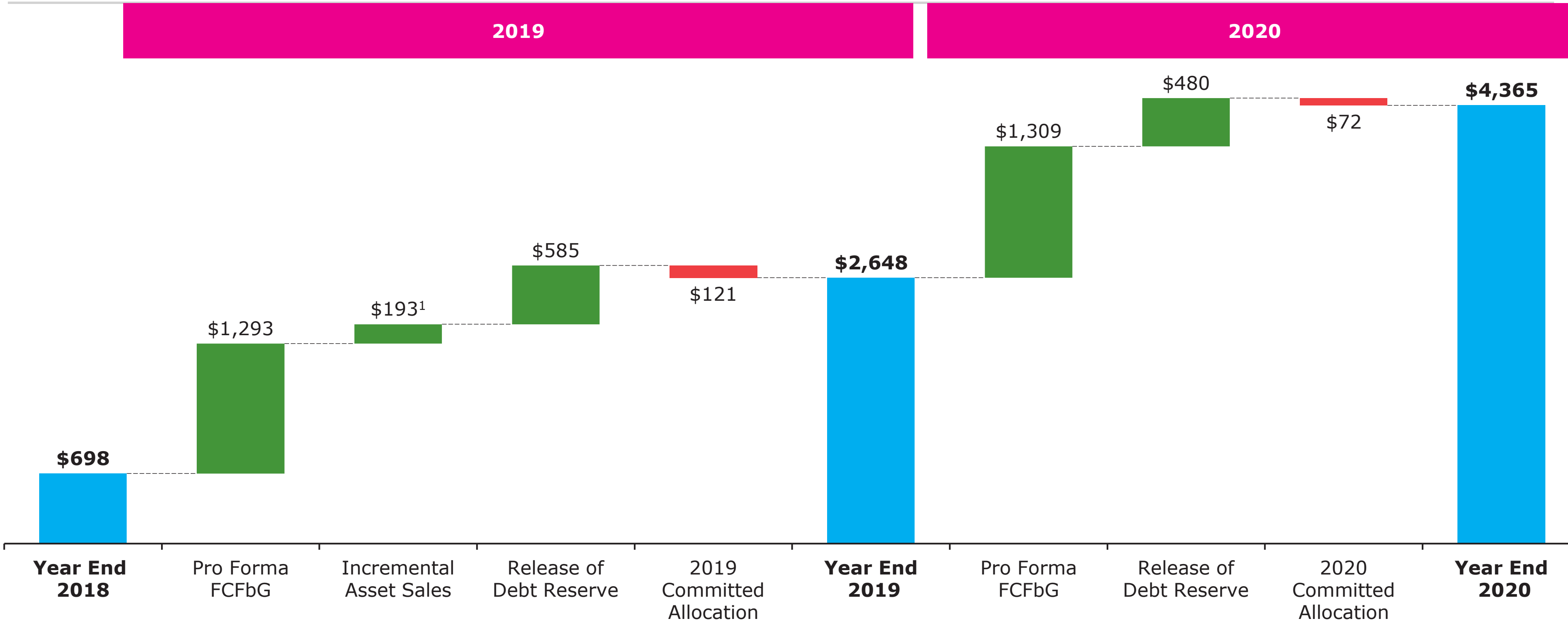
[1] Includes Corporate segment; [2] Based on midpoint of guidance range

GenOn Settlement

($ millions)	**July Payment** *(Payments to GenOn) / Payments to NRG*	**Impact**		
		FCFbG	**Capital Allocation**	**Collateral / Other**
Settlement	(261)	-	(261)	-
Credit for GenOn Senior Notes	(28)	-	(28)	-
Return of Collateral	(15)	-	-	(15)
Repayment of 2017 Intercompany Revolver Draw	125	-	125	-
Repayment of 2Q18 Intercompany Revolver Draw	26	-	-	26[1]
Interest on Intercompany Revolver	12	-	12	-
Remaining payments under Transition Services Agreement	10	10	-	-
Other balances due to NRG	6	-	6	-
Total July Payment	**(125)**	**10**	**(146)**	**11**
Pension (to be paid in 2018)			(14)	
Total Capital Allocation			**(160)**	

[1] Reflects GenOn's $26 MM draw on the intercompany revolver in June of 2018 which NRG funded through a draw on its corporate revolver. NRG subsequently repaid the corporate revolver in July 2018 (no impact to CAFA) concurrent with the $125 MM net payment to GenOn

Pro Forma Excess Cash 2018 to 2020



2018 Baseline (mid-point)	$1,000
XOOM Energy	45
Interest savings ($45 + 9)[2]	54
T. Plan add'l FCFbG[3]	194
Pro Forma 2019	$1,293

T. Plan add'l EBITDA[3]	$195
Target ratio	3.0x
	$585

Debt Amortization[2]	$ 68
Dividends	38
GenOn Pension	15
	$121

2019 Pro Forma	$1,293
T. Plan add'l FCFbG[3]	16
Pro Forma 2020	$1,309

T. Plan add'l EBITDA[3]	$80
MWG Corp EBITDA Incr.	80
Total	$160
Target ratio	3.0x
	$480

Debt Amortization	$19
Dividends	38
GenOn Pension	15
	$72

Continue to Expect >$4.3 Bn in Excess Capital through 2020

[1] Reduced by $12 MM due to the announced asset sales of Spanish Town and Keystone and Conemaugh; [2] See Analyst Day (3/27/2018) Appendix-Finance for footnotes; [3] See Analyst Day (3/27/2018) Appendix-Finance slide 4

Q2 2018 YTD Net Capital Expenditures

($ millions)	Maintenance	Environmental	Growth[1]	Total
Retail	$12	-	$22	$34
Generation				
Gulf Coast	70	-	-	70
East/West[2]	15	-	208	223
Renewables	2	-	286	288
NRG Yield	18	-	27	45
Corporate	6	-	25	31
Total Cash Capital Expenditures	**$123**	**-**	**$568**	**$691**
Other Investments[3]	-	-	286	286
Project Funding, net of fees[4]	-	-	(618)	(618)
Total Capital Expenditures and Growth Investments, net	**$123**	**-**	**$236**	**$359**

[1] Includes cost-to-achieve spend of $25 MM; [2] Also includes International. Includes growth capital spend related to Carlsbad and Canal 3; [3] Includes investments and acquisitions; [4] Includes net debt proceeds, cash grants and third-party contributions

Generation Organizational Structure

NRG Energy, Inc. (29,801[1] MW)

Renewables (690 MW)

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

Wind
- Broken Bow
- Buckthorn Wind
- Cedro Hill
- Crofton Bluffs
- Mountain Wind I&II
- Sherbino

NRG Yield (2,893 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 (13,692 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 (2,068 MW)

- Encina
- Long Beach
- Midway Sunset
- Saguaro
- 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

drop down to NRG Yield on March 27, 2017

Equity Investments

[1] Capacity controlled by NRG as of 6/30/2018, 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 6/30/2018

($ millions)

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

NRG Energy, Inc.		
Revolver $2.5 Bn due 2018/2021[1]	$	26
Senior notes due 2022-2028		4,801
Term loan due 2023		1,862
Tax exempt bonds due 2038-2045		465
Convertible Notes		575
Capital Lease		4
Total	**$**	**7,733**

Retained

Midwest Generation		
Capacity Monetization / Operating leases[2]	$	108

Other Financings		
Resi Solar	$	29
Other non-recourse debt	$	6

Asset Sales to be Completed

Agua Caliente		
Project financing due 2037	$	812
Borrower 1 due 2038		86

Other Renewables Financings		
Project financings	$	71

Announced Asset Sales

NRG Yield, Inc.		
Senior convertible notes due 2019-2020	$	633

NRG Yield Operating LLC		
Revolver $495 MM due 2019[3]	$	-
Senior Notes due 2024		500
Senior Notes due 2026		350

Yield Project Debt		
Conventional Term loans due 2023	$	973
Thermal Senior secured notes due 2031-2037		$328
Renewable Project Financings		$3,187

Renewables Financings		
Project financings	$	767

Carlsbad Energy		
Term Loan	$	513

Note: Debt balances exclude discounts and premiums
[1] $1,287 MM LC's issued and $1,222 MM Revolver available at NRG; [2] Excludes the present value of lease payments (9.1% discount rate) for Midwest Generation operating lease of $99 MM; this lease is guaranteed by NRG Energy, Inc.; [3] $67 MM of LC's were issued and $428 MM of the Revolver was available at NRG Yield

Recourse / Non-Recourse Debt

($ millions)	6/30/2018	3/31/2018	12/31/2017	9/30/2017
Recourse Debt				
Term Loan Facility	$ 1,862	$ 1,867	$ 1,872	$ 1,876
Senior Notes	4,801	4,845	4,845	5,449
Convertible Notes	575	-	-	-
Tax Exempt Bonds	465	465	465	465
Revolver	26	-	-	-
Capital Lease	4	4	4	6
Recourse Debt and Capital Lease Subtotal	**$ 7,733**	**$ 7,181**	**$ 7,186**	**$ 7,796**
Non-Recourse Debt				
Total NRG Yield[1,2]	$ 5,970	$ 6,038	$ 6,083	$ 5,901
Renewables (including capital leases)[2]	1,735	2,756	2,783	2,854
Conventional	657	613	586	587
Non-Recourse Debt Subtotal	**$ 8,362**	**$ 9,407**	**$ 9,452**	**$ 9,342**
Total Debt	**$ 16,095**	**$ 16,588**	**$ 16,638**	**$ 17,138**

Note: Debt balances exclude discounts and premiums
[1] Includes convertible notes and project financings; [2] Balance as of 6/30/2018 reflects deconsolidation of Ivanpah; balance as of 12/31/2017 recast to reflect sale of Buckthorn Solar to NRG Yield in 1Q18

Pro Forma Debt Analysis

$ millions

NRG Consolidated Debt as of 6/30/2018	**$16,095**
Less:	
Impact of divestitures (primarily NYLD and Renewables)[1]	(8,219)
Midwest Gen debt fully amortized	(108)
Resi Solar / Other non-recourse debt	(35)
NRG corporate debt as of 6/30/2018	**$7,733**
Repayment of Corporate revolver	(26)
Remaining convertible note proceeds for deleveraging	(531)
NRG pro forma corporate debt as of 6/30/2018	**$7,176**
Transformation plan deleveraging (target 3.0x)	(640)
Corporate Term Loan Amortization	(48)
2020 NRG pro-forma consolidated debt	**$6,488**

[1] See slide 36 – includes debt associated with *Asset Sales to be Completed* and *Announced Asset Sales*

2018 Announced Asset Sales

Asset(s)	$ MM[1]
Renewables / NRG Yield Interest	$ 1,375
South Central	1,000
NRG Yield ROFO Drop Downs to NRG Yield	407
Canal 3	130
BETM	70
Spanish Town and Keystone & Conemaugh	12
Total Proceeds	**$2,994**

[1] Excludes working capital and other purchase price adjustments

Appendix:
Reg. G Schedules

Reg. G: Q2 2018 QTD and YTD Free Cash Flow before Growth

($ millions)	QTD 6/30/2018	YTD 6/30/2018
Adjusted EBITDAR	**$ 849**	**$ 1,403**
Less: EME operating lease expense	(6)	(11)
Adjusted EBITDA	**$ 843**	**$ 1,392**
Interest payments	(181)	(368)
Income tax	(9)	(9)
Collateral / working capital / other	(486)	(491)
Cash Flow from Operations (continuing operations)	**$ 167**	**$ 524**
Gain on Sale of Land	-	3
Return of capital from equity investments[1]	(4)	(2)
Cost-to-Achieve[2]	22	44
Collateral	181	18
Adjusted Cash Flow from Operations	**$ 366**	**$ 587**
Maintenance capital expenditures, net	(59)	(123)
Environmental capital expenditures, net	-	-
Distributions to non-controlling interests	(48)	(98)
Consolidated Free Cash Flow before Growth	**$ 259**	**$ 366**
FCFbG at Non-Guarantor Subsidiaries[3]	52	67

[1] Represents cash distributions to NRG from equity investments, net of contribution to Petra Nova; [2] Includes costs associated with the Transformation Plan announced on 7/12/2017; [3] 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: Second Quarter 2018 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
Income/(Loss) from Continuing Operations	**305**	**(33)**	**272**	**(84)**	**(12)**	**96**	**(151)**	**121**
Plus:								
Interest expense, net	-	7	7	1	14	70	105	197
Income tax	-	-	-	-	(5)	7	6	8
Loss on debt extinguishment	-	-	-	-	-	-	1	1
Depreciation and amortization	43	23	66	31	40	82	8	227
ARO Expense	4	4	8	-	1	1	1	11
Contract amortization	3	-	3	-	-	18	-	21
Lease amortization	-	(2)	(2)	-	-	-	-	(2)
EBITDA	**355**	**(1)**	**354**	**(52)**	**38**	**274**	**(30)**	**584**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	3	5	8	(6)	4	33	2	41
Acquisition-related transaction & integration costs	-	-	-	1	-	1	-	2
Reorganization costs	2	1	3	1	3	-	16	23
Deactivation costs	-	7	7	-	-	-	3	10
Gain on sale of assets	-	-	-	-	-	-	(14)	(14)
Other non recurring charges	19	2	21	8	10	(5)	18	52
Impairments	-	74	74	-	-	-	-	74
Mark to market (MtM) (gains)/losses on economic hedges	(285)	15	(270)	346	(5)	-	-	71
Adjusted EBITDA	**94**	**103**	**197**	**298**	**50**	**303**	**(5)**	**843**

[1] Includes International, BETM and generation eliminations

Reg. G

Appendix Table A-3: Second Quarter YTD 2018 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
Income/(Loss) from Continuing Operations	**(261)**	**(4)**	**(265)**	**861**	**(45)**	**96**	**(293)**	**354**
Plus:								
Interest expense, net	-	10	10	2	28	124	196	360
Income tax	-	-	-	-	(11)	6	12	7
Loss on debt extinguishment	-	-	-	-	-	-	3	3
Depreciation and amortization	86	47	133	59	90	163	17	462
ARO Expense	11	8	19	2	2	2	(2)	23
Contract amortization	5	1	6	-	-	35	-	41
Lease amortization	-	(5)	(5)	-	-	-	1	(4)
EBITDA	**(159)**	**57**	**(102)**	**924**	**64**	**426**	**(66)**	**1,246**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	2	12	14	(12)	7	67	-	76
Acquisition-related transaction & integration costs	-	-	-	3	-	2	1	6
Reorganization costs	4	3	7	4	3	-	29	43
Deactivation costs	-	10	10	-	-	-	6	16
Gain on sale of business	-	-	-	-	1	-	(14)	(13)
Other non-recurring charges	26	5	31	7	1	(3)	33	69
Impairments	-	74	74	-	-	-	-	74
Mark to market (MtM) (gains)/losses on economic hedges	282	28	310	(440)	5	-	-	(125)
Adjusted EBITDA	**155**	**189**	**344**	**486**	**81**	**492**	**(11)**	**1,392**

[1] Includes International, BETM and generation eliminations

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Appendix Table A-4: Second 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
Income/(Loss) from Continuing Operations	**(148)**	**58**	**(90)**	**341**	**(46)**	**44**	**(150)**	**99**
Plus:								
Interest expense, net	-	8	8	1	25	88	123	245
Income tax	-	2	2	(12)	(5)	8	11	4
Depreciation and amortization	68	27	95	29	49	79	8	260
ARO Expense	4	2	6	-	-	1	-	7
Contract amortization	4	1	5	-	-	17	-	22
Lease amortization	-	(2)	(2)	-	-	-	-	(2)
EBITDA	**(72)**	**96**	**24**	**359**	**23**	**237**	**(8)**	**635**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	15	5	20	(3)	(5)	34	1	47
Acquisition-related transaction & integration costs	-	-	-	-	-	1	-	1
Deactivation costs	-	(1)	(1)	-	-	-	4	3
Other non-recurring charges	(25)	(1)	(26)	4	9	2	7	(4)
Impairments	42	(1)	41	-	22	-	-	63
Mark to market (MtM) (gains)/losses on economic hedges	105	(11)	94	(156)	3	-	-	(59)
Adjusted EBITDA	**65**	**87**	**152**	**204**	**52**	**274**	**4**	**686**

[1] Includes International, BETM and generation eliminations

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Appendix Table A-5: Second Quarter YTD 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
Income/(Loss) from Continuing Operations	**(105)**	**51**	**(54)**	**311**	**(77)**	**42**	**(292)**	**(70)**
Plus:								
Interest expense, net	-	17	17	3	48	163	235	466
Income tax	-	2	2	(9)	(10)	7	9	(1)
Loss on debt extinguishment	-	-	-	-	-	2	-	2
Depreciation and amortization	138	54	192	57	96	156	16	517
ARO Expense	7	6	13	-	1	2	-	16
Contract amortization	8	2	10	1	-	34	-	45
Lease amortization	(1)	(4)	(5)	-	-	-	1	(4)
EBITDA	**47**	**128**	**175**	**363**	**58**	**406**	**(31)**	**971**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	21	12	33	(6)	(10)	47	1	65
Acquisition-related transaction & integration costs	-	-	-	-	-	2	(1)	1
Deactivation costs	-	1	1	-	-	-	4	5
Other non-recurring charges	(23)	(3)	(26)	-	8	5	19	6
Impairments	42	(1)	41	-	22	-	-	63
Mark to market (MtM) (gains)/losses on economic hedges	(17)	(1)	(18)	(20)	(3)	-	-	(41)
Adjusted EBITDA	**70**	**136**	**206**	**337**	**75**	**460**	**(8)**	**1,070**

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

($ millions)	Midwest Gen	Ivanpah
Net (loss)/income	**69**	**(6)**
Plus:		
Income tax	-	-
Interest expense, net	-	35
Depreciation, Amortization, Contract Amortization, and ARO Expense	50	71
EBITDA	**119**	**100**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	-
Deactivation costs	3	-
Other non-recurring charges	-	-
Mark to market (MtM) losses on economic hedges	3	-
Plus: Operating lease expense	22	-
Adjusted EBITDAR	**147**	**100**
Less: Operating lease expense	(22)	-
Adjusted EBITDA - Standalone	**125**	**100**

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Appendix Table A-9: 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]	**206**	**17**
Plus:		
Income tax	25	(25)
Interest expense, net	320	33
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
Adjusted 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

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Appendix Table A-10: XOOM Energy Adjusted EBITDA Guidance: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

($ millions)	**2018**
Net income/(loss)	**11**
Plus:	
Income tax	-
Interest expense, net	-
Depreciation, Amortization, Contract Amortization, and ARO expense	34
EBITDA	**45**
Adjustment to reflect NRG share of Adjusted EBITDA	-
Acquisition-related transaction & integration costs	-
Deactivation Costs	-
Reorganization costs	-
Other non recurring charges	-
Mark-to-Market (MtM) losses/(gains) on economic hedges	-
Adjusted EBITDA	**45**

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

	Pro Forma	
($ millions)	**2018**	**2020**
GAAP Net Income[1]	303	900
Income tax	20	20
Interest Expense	402	342
Depreciation, Amortization, Contract Amortization, and ARO Expense	485	485
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	123	123
Other Costs[2]	267	5
Adjusted EBITDA	**$1,600**	**$1,875**

[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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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.