NRG Energy Inc.

First Quarter 2018 Earnings Presentation

May 3, 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 May 3, 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 First Quarter Results;
Execution of Transformation Plan Remains Top Priority**

Platform Well-Positioned for Upside in Power Markets

NRG Analyst Day Introduces Long-Term Strategic Positioning and Highlights Potential for Significant Excess Cash

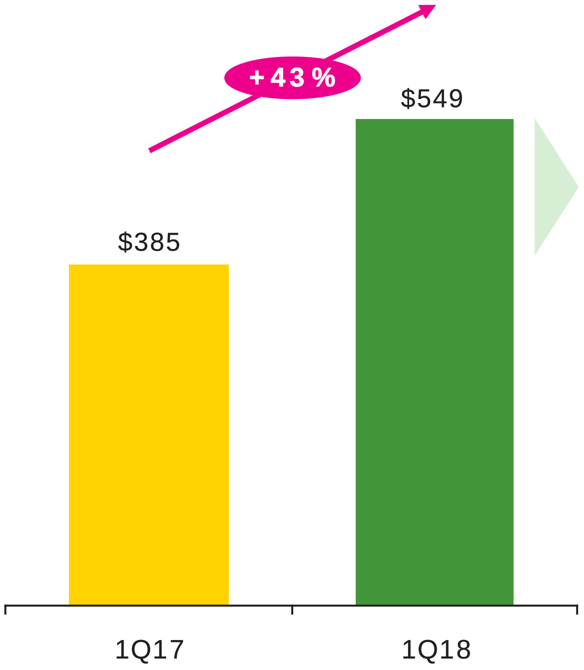
Q1 Results and Highlights

Q1 Business Highlights

- **Strong Q1: $549 MM of Adj. EBITDA. Maintaining 2018 guidance**
  - Top decile safety performance
- **Continued execution of Transformation Plan:**
  - Achieved $80 MM in cost savings through 3/31/2018; on track for total cost savings of $590 MM
  - Asset sale approvals on track to close in 2H18
- **Disciplined capital allocation:**
  - Acquired XOOM Energy for returns in excess of 12-15% hurdle rate
  - Executed $93 MM of share repurchases in Q1; expect to complete $1 Bn program in 2018
- **March Analyst Day provided long-term strategy**

Consolidated Q1 Results

Adjusted EBITDA ($ MM)



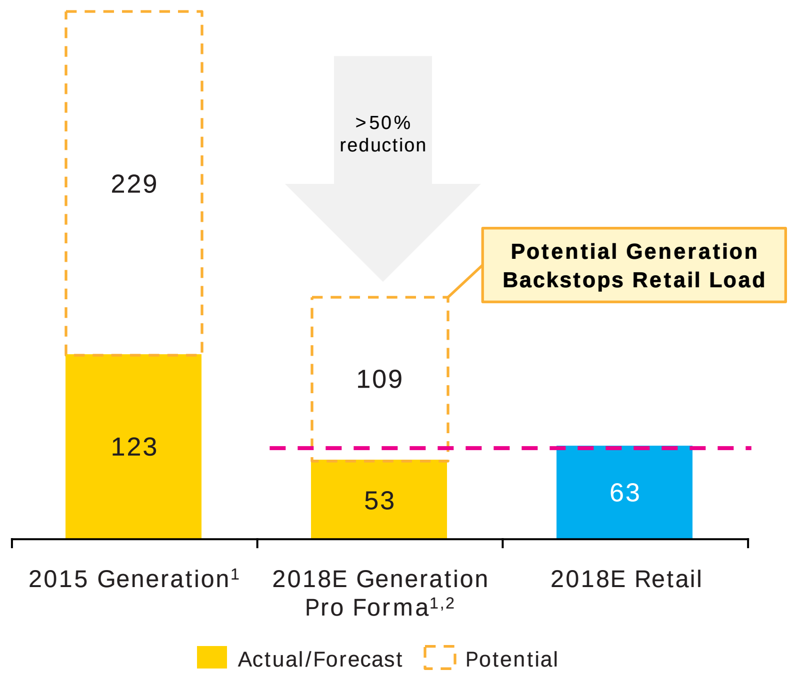
Drivers:
- Cost savings
- Colder January
- Higher power prices

43% Adjusted EBITDA Growth Year over Year;
Transformation Plan Initiatives On Track

Analyst Day 2018 Recap: Strengthened Integrated Platform

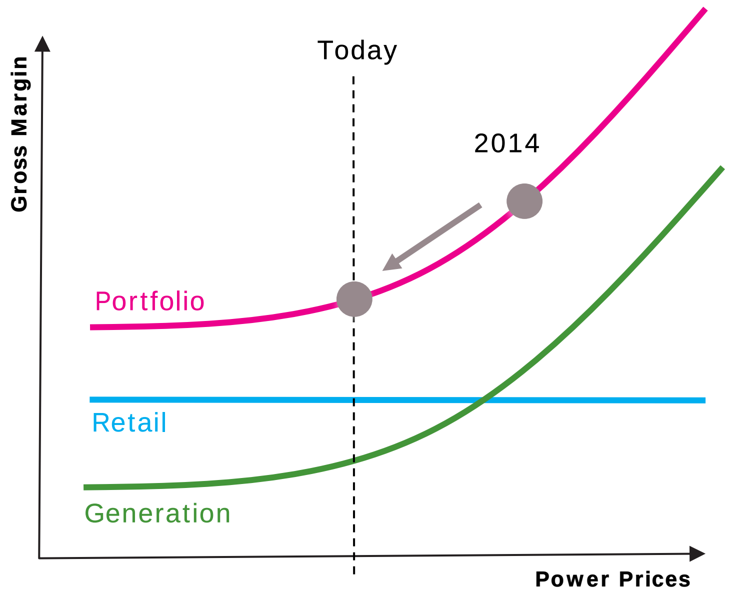
Right-Sized Generation Portfolio Better Matches Retail…

NRG Portfolio (TWh)



…Creating Predictable Earnings with Asymmetric Upside

Gross Margin vs Power Prices



Indicative Chart

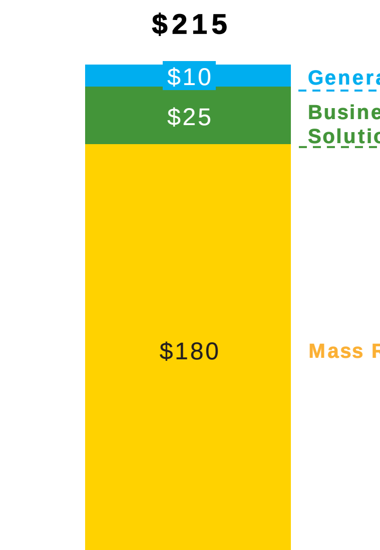
Integrated Platform Provides Predictable Cash Flows with Attractive Market Opportunities

[1] Potential generation based on 85% capacity factor for conventional generation; [2] Pro Forma for announced asset sales

Analyst Day 2018 Recap: Executing Financial Priorities

Clear Path to EBITDA Margin Enhancement: $215 MM by 2020

($ MM)



2020 Target: EBITDA-Margin Enhancement

Example Sources

Generation	Further integration with Retail
Business Solutions	Technology and infrastructure
Mass Retail	**Value Expansion $105** • Retention performance • Platform enhancements • Product expansion **Customer Growth $75** • Digital selling • Channel performance • Channel expansion

Investing **$75 MM[2]** of CTA in Our Business to Support Margin Enhancement

Disciplined, Transparent Allocation Plan for Significant Excess Cash

1. Maintain top decile safety and operational excellence
2. Execute plan and achieve ~$8 Bn[1] in excess cash through 2022
3. Allocate capital using core principles:

- [x] Maintain 3.0x Net Debt / Adj. EBITDA
- [ ] Reinvest at or above hurdle rate of 12-15% unlevered pretax return with 5-yr or less payback
- [ ] Return capital to shareholders

Illustrative Use of Cash through 2022

~2x FCFbG Growth if 100% Reinvested[3]

~80% of Market Cap if 100% Buybacks[4]

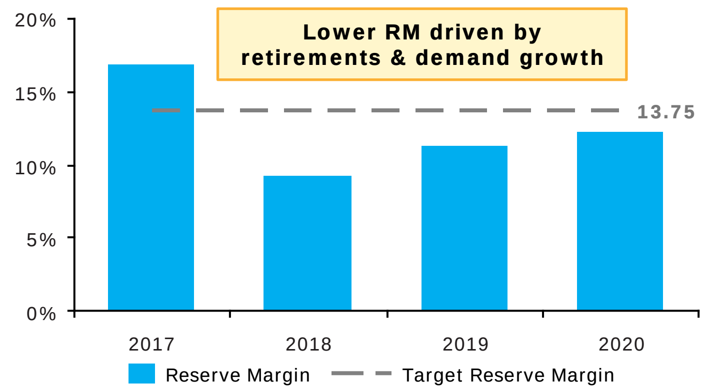
Strengthened Platform to Generate ~$8 Bn in Excess Cash through 2022

[1] Includes $1 Bn of excess cash allocated to buybacks; [2] Part of $290 MM one-time cost to achieve (CTA) disclosed in the July 2017 Transformation Plan; [3] Assumes an unlevered return of 12-15%, 40% leverage and 6.5% interest expense; full year's cash is invested mid-year; growth factor based on 2018 guidance; [4] Uses 5/2/2018 share price of $30.48

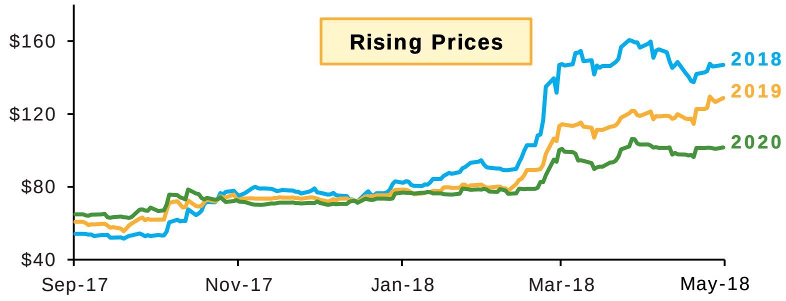
Market Outlook - ERCOT

Market Tightening in ERCOT Impacting Forward Prices...

ERCOT Reserve Margins (RM) (%)[1]

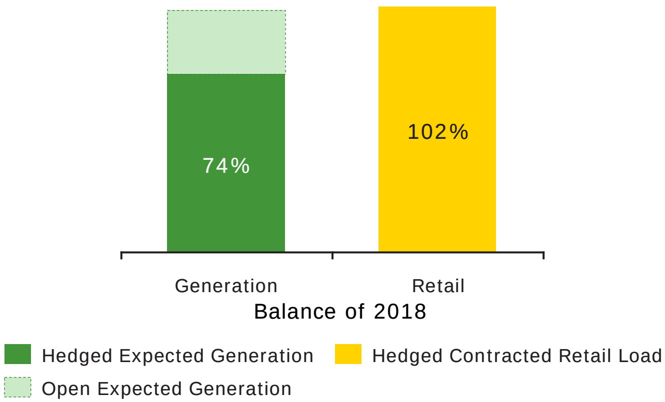


Houston Summer On-Peak[2] ($/MWh)



...NRG Integrated Platform Positioned for Upside this Summer and Beyond

ERCOT Total Portfolio Generation and Retail Hedge Position[3,4]



- Integrated platform **well-positioned** for summer
- **Strengthened Generation fleet** ahead of summer
  - Leaning long this summer; significant upside beyond '18
  - Expanded spring outage work
  - Purchased forced outage insurance
- **Retail business prepared** for high price conditions
  - Priced-load fully hedged
  - Purchased options for high load/price scenario
  - Customer outreach and education

Well-Positioned to Benefit from Improving Market Conditions in ERCOT

[1] 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; [2] Average Houston Hub July-August on-peak power; [3] Balance 2018 reflects April through December; [4] Hedged Expected Generation includes heat rate hedges in ERCOT

Market Outlook - East

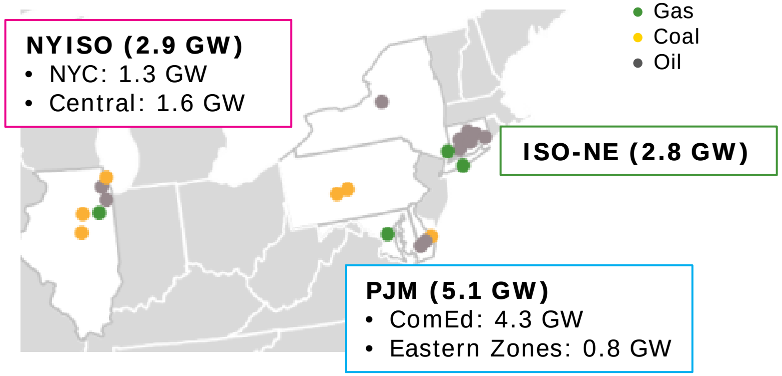
2021/2022 PJM Capacity Auction

Market Drivers	
Retirements	7.5 GW added to PJM deactivation list during 2018; includes 4 GW of nuclear determined by PJM not to be needed for reliability
Slowed New Build	20/21 auction cleared 2.4 GW of new build, ~50% less than average of previous 3 years
State Subsidies	NJ Bill pending Governor action. Year two for IL subsidies. Uncertain impact to participant offers
Zonal Transfer Ratios	COMED and EMAAC separation potential remains despite CETL[1] increases
Stagnant Load	RTO reliability requirement down 1% year-on-year

Potential for Market Tightening Uncertain Due to Out of Market Compensation Requests

NRG Fleet Well-Located and Diverse

NRG East Generation Fleet



- **NRG Generation Fleet Well-Positioned:**
  - Fuel diversity provides resilience attributes
  - Majority of MWs located in premium capacity areas
  - Positioned near load-centers
- **Continued Calls for Price Reform Across Markets:**
  - PJM Energy and Capacity market reforms
  - ISO-NE capacity market reform
  - FERC focus on market resilience

NRG Fleet Remains Well-Positioned for Regulatory and Market Reform in the East

[1] Capacity Emergency Transfer Limit

Financial Update

Financial Summary

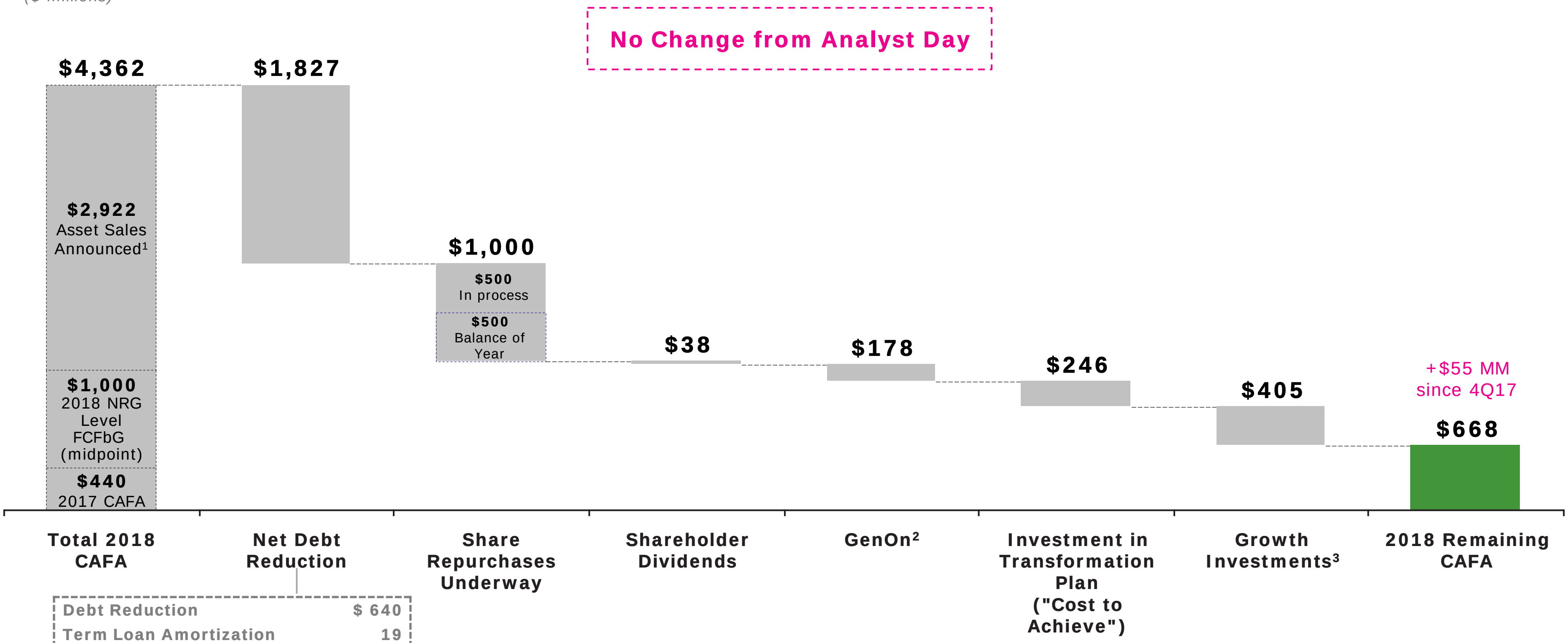
($ millions)	3 Months Ended 3/31/18	Full Year Guidance	Full Year Impact – Asset Sales: Announced	Full Year Impact – Asset Sales: To be Completed	Pro Forma[2]
Generation & Renewables[1]	$172	$950 – $1,050	*($255)*	*($100)*	~$650
Retail	188	900 – 1,000	–	–	~950
NRG Yield	189	950	*(950)*	–	–
Adjusted EBITDA	**$549**	**$2,800 - $3,000**	*($1,205)*	*($100)*	**~$1,600**

- Strong Q1 results from improved power pricing and retail volumes, as well as cost reductions
- Maintaining 2018 guidance
- Term loan repricing reduces annual cash interest by $9 MM
- Canal 3 sale expected to enhance 2018 capital allocation by $130 MM[3] – expected to close in 3Q18
- XOOM acquisition for $210 MM[4] expected to contribute ~$45 MM of Adjusted EBITDA annually
- Completed sale of Buckthorn Solar to NRG Yield for $42 MM
- 3.1 million shares repurchased in March for $93 MM (average of $29.75/share)

[1] Includes Corporate Segment; [2] Based on midpoint of guidance range; [3] Excludes adjustments for working capital; [4] Includes transaction costs and working capital; subject to other customary purchase price adjustments

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

Canal 3 Proceeds and Partial Release of Reserve More than Offset Purchase of XOOM

[1] Now includes $130 MM from sale of Canal 3 (as announced at Analyst Day, 3/27/2018) – see appendix slide 36 for list of announced asset sales; [2] Comprised of $261 MM for GenOn settlement, ($125 MM) repayment of loan by GenOn, $28 MM agreed as part of settlement plus $14 MM in pension funding in 2018; [3] Net of financing, includes $210 MM for XOOM acquisition; [4] $103 MM of 2018 capacity revenue sold forward in 2016; 2018 payment to counterparty treated as debt amortization for accounting purposes

Corporate Credit Metrics

$ millions	2018 Pro-Forma	MWG	T. Plan	2020 Pro-Forma
Corporate Debt[1]	**$7,181**			**~$6,530**
2018 Term Loan Amortization	(14)			(38)
Additional Debt Reduction (2018)	(640)			--
Pro Forma Corporate Debt	**~$6,530**			**~$6,492**
Cash & Cash Equivalents @ NRG-Level/Min Cash	(500)			(500)
Cash Reserve to meet 3.0x target	(1,065)			C --
Pro Forma Corporate Net Debt	**~$4,965**			**~$5,992**
Pro-Forma Adj. EBITDA	**$1,600**	--	A $275	**$1,875**
Plus: XOOM Adj. EBITDA (pro forma)	45			45
Pro-Forma Adj. EBITDA (incl XOOM)	**$1,645**			**$1,920**
Less: Ivanpah & MidwestGen Adj. EBITDA	(225)	B 125		(100)
Add: Ivanpah & MidwestGen Cash Distributions to NRG	65	(45)		20
Other Adjustments[2]	150			150
Total Recourse Adj. EBITDA	**$1,635**	**$80**	**$275**	**$1,990**
Corporate Net Debt/Corporate Adj. EBITDA	**3.0x**			**3.0x**
Remaining Excess CAFA excluded from cash:	**$668**			**$4,347**

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

Cash Reserve to Maintain 3.0x Corporate Credit Ratio Fully Released by 2020[3]

[1] 2018 reflects balance at 3/31/2018 - includes NRG Energy, Inc. term loan facility, senior notes, revolver, capital leases and tax exempt bonds; [2] Reflects non-cash expenses (i.e. nuclear amortization, equity compensation amortization, and bad debt expense) that are included in Adjusted EBITDA; [3] See appendix slide 31 for details supporting release of cash reserve by 2020; [4] Final year of capacity monetization

Closing Remarks

2018 Priorities and Expectations

☐ **Deliver on Financial and Operational Objectives**

- ☑ Maintaining full year guidance ranges
- ☑ Strong Q1 financial, operational and safety performance
- ☐ Execute $1 Bn share repurchase program ($93 MM completed in March)

☐ **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 of Buckthorn Solar to NRG Yield for $42 MM
- ☐ NRG Yield / Renewables / ROFO, South Central, BETM, and Canal 3 asset sales expected to close in second half of 2018
- ☐ Announce remaining $205 MM targeted Transformation Plan asset sales
- ☐ XOOM acquisition to close in 2Q18
- ☐ GenOn expected to emerge from bankruptcy; transition services expected to end on or before 9/30/2018

☑ **Provided Long-Term Strategy at March 27, 2018 Analyst Day**

Q&A

Appendix

Transformation Plan Score Card

2018 Progress as of 3/31/2018

($ millions)	YTD Realized	YTD % Achieved	2018 Target
Accretive & Recurring:			
Cost Savings	80	*16%*	500
Margin Enhancement	0	*0%*	30
Total EBITDA - Accretion	**$80**	***15%***	**$530**
Maintenance Capex	9	*30%*	30
Total Recurring FCFbG - Accretion	**$89**	***16%***	**$560**
Non-Recurring:			
Working Capital Improvement	21	*25%*	85
Cost to Achieve Total Transformation Plan	(39)	-	(246)
Total Non-Recurring	**($18)**	**-**	**($161)**
Annual Cash Accretion	**$71**	***18%***	**$399**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**~$398**	***55%***	**~$726**

Transformation Plan Target

($ 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

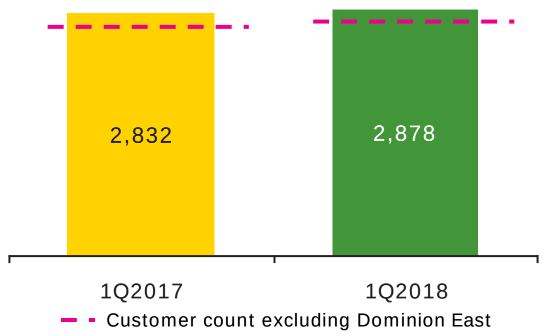
Retail: Operational Metrics

Q1 Summary

- Delivered $188 MM in Adjusted EBITDA, $55 MM higher than 1Q17
- Reduced operating costs year over year, despite having 45,000 more customers than 1Q17
- Continued leadership in customer experience, with Reliant taking #1 spot nationally (ForeSee 25 Largest Utility Providers)

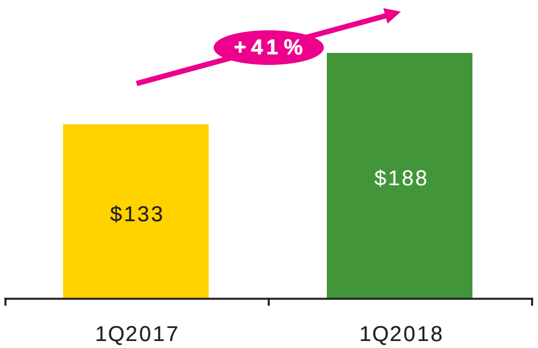
Growth in Q1 Mass Customer Count

Mass Recurring Customers[1] (000s)



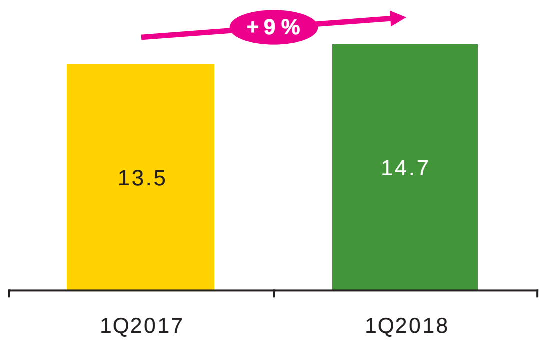
Strong Q1 EBITDA Earnings

Adjusted EBITDA ($ millions)



Higher Q1 Volumes

Delivered TWh

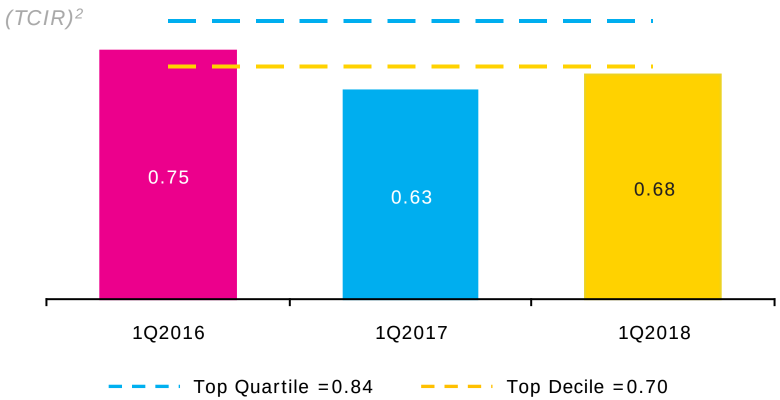


Retail Delivers Strong First Quarter of 2018

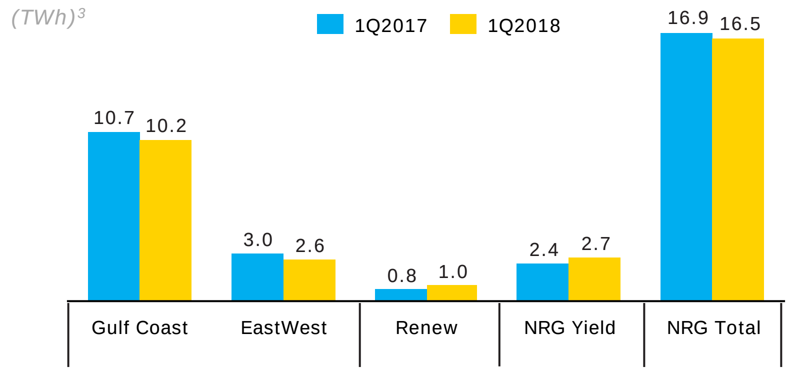
[1] Mass recurring customer count includes customers that subscribe to one or more recurring services, such as electricity and natural gas; excludes C&I customers

Generation: Operational Metrics

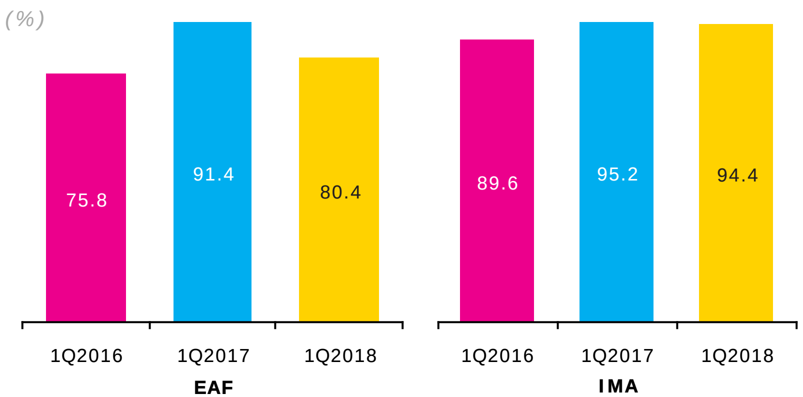
Safety[1]



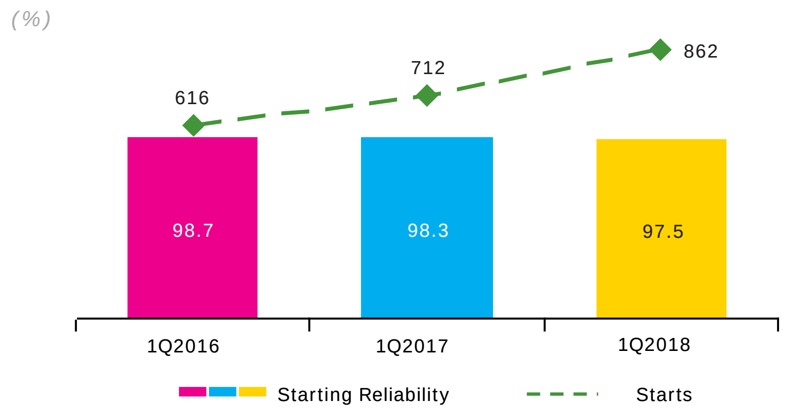
Production



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



Gas and Oil Starts and Reliability

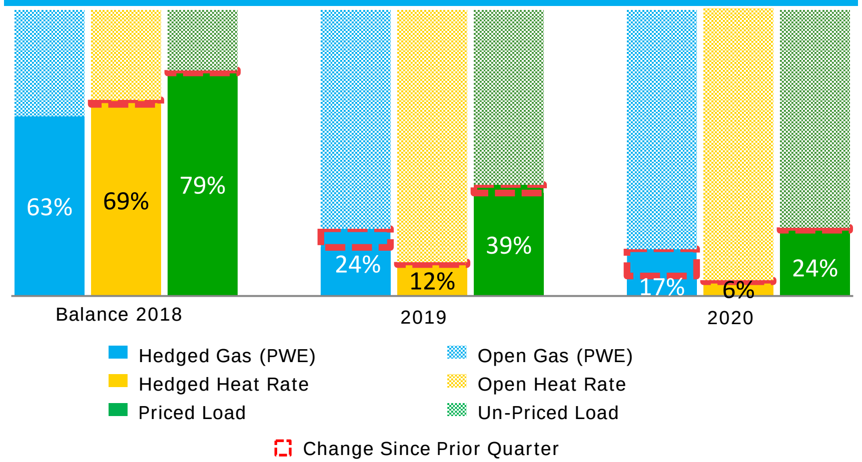


Top Decile Safety Results and Strong In the Money Availability

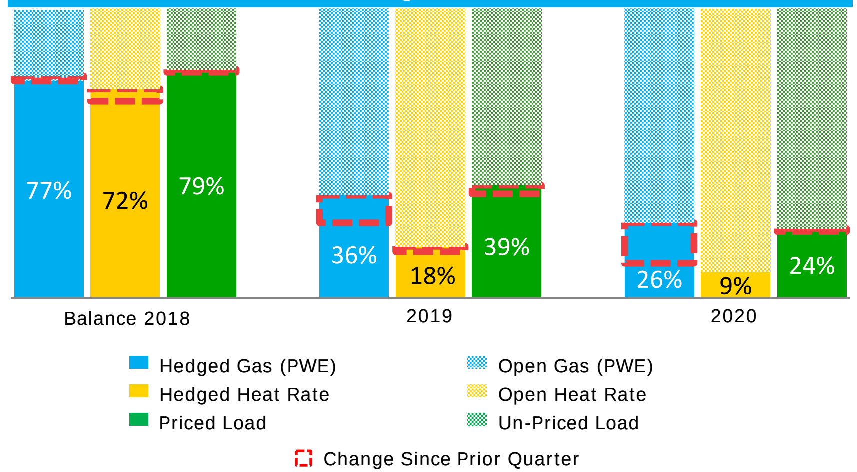
[1] Excludes Goal Zero, NRG Home Services and NRG Home Solar; top decile and top quartile based on Edison Electric Institute 2015 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation; excludes line losses, station service, and other items. Generation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

Pro Forma Portfolio[1] Managing Commodity Price Risk

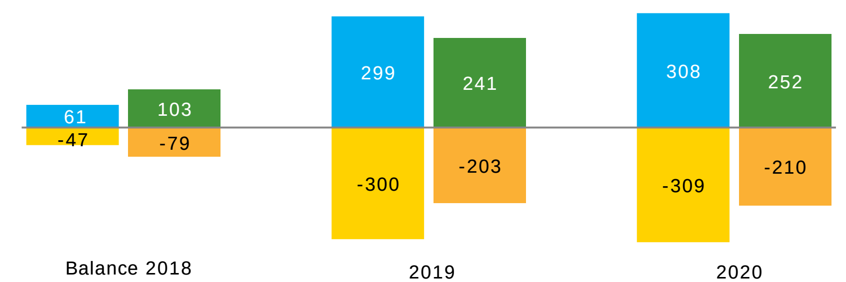
Total Portfolio Generation and Retail Hedge Position[1,2]



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



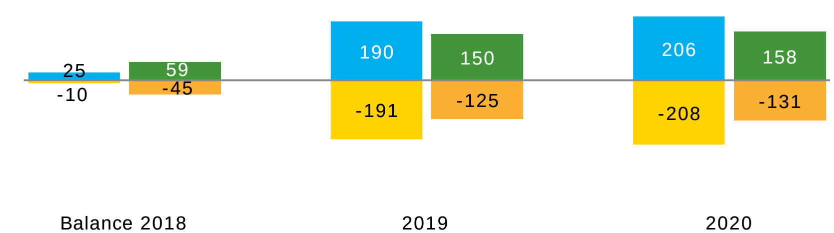
Total Portfolio Sensitivity to Gas Price and Heat Rate[1,3]



Henry Hub Gas as of 3/29	2.83	2.79	2.78

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]



Henry Hub Gas as of 3/29	2.83	2.79	2.78

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 3/29/2018, includes Texas, PJM, NY, NE, CAISO & Cottonwood, excludes GenOn, MISO, Yield & Renew; Balance 2018 reflects April 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 99%, 41%, and 24% for 2018, 2019, and 2020, respectively

1Q18 Hedge Disclosure: Coal and Nuclear Operations

Coal & Nuclear Portfolio[1]

Gross Margin Sensitivities $ in MM		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]	4,191	3,947	3,902	1,267	1,218	1,049
	Total Coal and Nuclear Sales (GWh)[4]	19,853	14,497	10,655	7,979	1,573	674
	Percentage Coal and Nuclear Capacity Sold Forward[5]	72%	42%	31%	95%	15%	7%
	Total Forward Hedged Revenues [6]	$816	$621	$396	$248	$48	$21
	Weighted Average Hedged Price ($ per MWh)[6]	$41.12	$42.84	$37.15	$31.08	$30.46	$30.58
	Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$1.73	$2.63	$2.64	$2.88	$2.88	$2.70
Gross Margin Sensitivities $ in MM	Gas Price Sensitivity Up $0.50/mmBtu on Coal and Nuclear Units	($9)	$82	$100	$34	$108	$106
Gross Margin Sensitivities $ in MM	Gas Price Sensitivity Down $0.50/mmBtu on Coal and Nuclear Units	$10	($113)	($135)	($20)	($78)	($73)
Gross Margin Sensitivities $ in MM	Heat Rate Sensitivity Up 1 mmBtu/MWh on Coal and Nuclear Units	$35	$89	$98	$24	$61	$60
Gross Margin Sensitivities $ in MM	Heat Rate Sensitivity Down 1 mmBtu/MWh on Coal and Nuclear Units	($25)	($78)	($86)	($20)	($48)	($45)

1 Portfolio as of 3/29/2018. Includes Texas and PJM; Excludes MISO. Balance 2018 reflects April 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 3/29/2018 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 3/29/2018 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 coal and nuclear sales

3Q17 Hedge Disclosure: Coal and Nuclear Operations

Updated for Asset Sales, for Modeling Purposes

Coal & Nuclear Portfolio[1]	Texas 2018	Texas 2019	Texas 2020	East 2018	East 2019	East 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]	4,125	3,923	3,844	1,507	1,330	1,099
Total Coal and Nuclear Sales (GWh)[4]	24,154	689	NA	13,218	1,474	603
Percentage Coal and Nuclear Capacity Sold Forward[5]	67%	2%	NA	100%	13%	6%
Total Forward Hedged Revenues [6]	$950	$32	NA	$427	$45	$18
Weighted Average Hedged Price ($ per MWh)[6]	$39.31	$46.72	NA	$32.34	$30.37	$30.38
Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$3.05	$3.81	NA	$3.06	$2.97	$2.82
Gross Margin Sensitivities $ in MM: Gas Price Sensitivity Up $0.50/mmBtu on Coal and Nuclear Units	$11	$146	$151	$36	$107	$106
Gross Margin Sensitivities $ in MM: Gas Price Sensitivity Down $0.50/mmBtu on Coal and Nuclear Units	$8	($143)	($149)	($23)	($84)	($77)
Gross Margin Sensitivities $ in MM: Heat Rate Sensitivity Up 1 mmBtu/MWh on Coal and Nuclear Units	$74	$97	$104	$27	$64	$60
Gross Margin Sensitivities $ in MM: Heat Rate Sensitivity Down 1 mmBtuMWh on Coal and Nuclear Units	($60)	($86)	($88)	($22)	($55)	($50)

1 Portfolio as of 10/26/2017. 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 10/26/2017 which is then divided by number of hours in a given year to arrive at MW capacity; The dispatch takes into account planned and unplanned outage assumptions
4 Includes amounts under power sales contracts and natural gas hedges; the forward natural gas quantities are reflected in equivalent GWh based on forward market implied heat rate as of 10/26/2017 and then combined with power sales to arrive at equivalent GWh hedged; the Coal and Nuclear Sales include swaps and delta of options sold which is subject to change; actual value of options will include the impact of non-linear factors; for detailed information on the Company's hedging methodology through use of derivative instruments, see discussion in 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 coal and nuclear sales

Commodity Prices

Forward Prices[1]	Bal-2018[2]	2019	2020	Annual Average for 2018-2020
NG Henry Hub ($/mmBtu)	$2.83	$2.79	$2.78	$2.80
PRB 8800 ($/ton)	$12.62	$12.41	$12.30	$12.44
ERCOT Houston Onpeak ($/MWh)	$63.41	$46.26	$42.91	$50.86
ERCOT Houston Offpeak ($/MWh)	$24.03	$22.21	$21.70	$22.65
PJM West Onpeak ($/MWh)	$35.20	$35.60	$35.31	$35.37
PJM West Offpeak ($/MWh)	$25.02	$26.55	$26.34	$25.97

	Change since establishing 2018 guidance (3Q17 call)	
Price Variance[1]	As of 3/29/2018	As of 4/30/2018
NG Henry Hub ($/mmBtu)	($0.17)	($0.20)
PRB 8800 ($/ton)	$0.40	$0.28
ERCOT Houston Onpeak ($/MWh)	$22.23	$18.74
ERCOT Houston Offpeak ($/MWh)	$0.92	$0.48
PJM West Onpeak ($/MWh)	$0.98	$1.83
PJM West Offpeak ($/MWh)	$1.57	$2.30

[1] Prices as of 3/29/2018; [2] Represents April through December months

Fuel Statistics

	1Q		YTD	
Domestic[1]	**2018**	**2017**	**2018**	**2017**
Coal Consumed (mm Tons)	4.6	5.2	4.6	5.2
PRB Blend	**99%**	**94%**	**99%**	**94%**
East	96%	98%	96%	98%
Gulf Coast	100%	93%	100%	93%
Bituminous	**1%**	**1 %**	**1%**	**1%**
East	4%	2%	4%	2%
Lignite	**0%**	**5%**	**0%**	**5%**
Gulf Coast	0%	7%	0%	7%
Cost of Coal ($/Ton)	**$ 32.37**	**$ 32.47**	**$ 32.37**	**$ 32.47**
Cost of Coal ($/mmBtu)	**$ 1.89**	**$ 1.91**	**$ 1.89**	**$ 1.91**
Cost of Gas ($/mmBtu)	**$ 3.42**	**$ 3.09**	**$ 3.42**	**$ 3.09**

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

Q1 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	10,187	10,689	(503)	(5%)	82%	39%	87%	39%
East/West	2,561	3,017	(456)	(15%)	86%	10%	91%	12%
Renewables	1,015	915	101	11%	98%	37%	99%	39%
NRG Yield[4]	2,691	2,405	286	12%	92%	20%	91%	18%
Total	**16,454**	**17,026**	**(572)**	**(3%)**	**85%**	**26%**	**89%**	**27%**
Gulf Coast – Texas Nuclear	2,315	2,319	(5)	(0%)	96%	91%	92%	91%
Gulf Coast – Texas Coal	4,607	5,015	(408)	(8%)	75%	60%	93%	63%
Gulf Coast – South Central Coal	804	965	(161)	(17%)	73%	41%	81%	49%
East Coal	1,832	2,302	(471)	(20%)	83%	26%	92%	33%
Baseload	**9,558**	**10,601**	**(1,044)**	**(10%)**	**80%**	**52%**	**92%**	**56%**
Renewables Solar	405	311	95	30%	98%	26%	99%	40%
Renewables Wind	610	604	6	1%	98%	43%	98%	39%
NRG Yield Solar	247	228	19	8%	99%	23%	99%	22%
NRG Yield Wind	1,370	1,449	(79)	(5%)	97%	31%	97%	33%
Intermittent	**2,632**	**2,592**	**40**	**2%**	**97%**	**32%**	**98%**	**33%**
East Oil	142	25	117	466%	95%	2%	94%	0%
Gulf Coast – Texas Gas	533	387	147	38%	85%	5%	78%	3%
Gulf Coast – South Central Gas	1,927	2,003	(76)	(4%)	89%	34%	91%	35%
East Gas	149	178	(29)	(16%)	85%	2%	93%	2%
West Gas	439	512	(73)	(14%)	75%	11%	83%	13%
NRG Yield Conventional	438	142	296	208%	85%	10%	84%	3%
NRG Yield Thermal[4]	637	585	52	9%	98%	5%	100%	3%
Intermediate / Peaking	**4,265**	**3,833**	**432**	**11%**	**86%**	**9%**	**86%**	**8%**

[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	$326	$327	$286
NYISO	$100	$40	$11
NE-ISO	$157	$149	$110
Ivanpah	$131	$132	$135

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	2017-2018	$7.03	1,534	1,534
		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	$4.29	1,935	2,816
		2019	$4.45	742	2,820
		2020	$6.70	136	2,820
		2021	-	-	2,820

Assumptions:
- ISO-NE and NYISO data as of 2/28/2018
- 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 2/28/2018 and is subject to change; [3] NYISO - NYC estimated qualified capacity is 1.3 GW; NYISO - Central estimated qualified capacity is 1.6 GW

Capacity Clears: NRG Standalone (Cont'd)

			Base Product		Capacity Performance Product	
Market	**Region**	**Planning Year**	**Average Price ($/MW-Day)**	**MWs Cleared**	**Average Price ($/MW-Day)**	**MWs Cleared**
PJM	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
PJM	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
PJM	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
PJM	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
PJM	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
PJM	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

Assumptions:
- PJM data as of 5/23/2017
- Includes imports
- Excludes NRG Yield Assets

Pro Forma Asset List[1]: Merchant Wholesale Generation

ERCOT

ERCOT (10,159 MW, Net)				
Name	Location	Capacity	Entity	Ownership %
Cedar Bayou	Baytown, TX	1,495	NRG	100%
Cedar Bayou 4	Baytown, TX	249	NRG	50%
Greens Bayou	Houston, TX	344	NRG	100%
Petra Nova	Thompsons, TX	22	NRG	50%
San Jacinto	La Porte, TX	162	NRG	100%
TH Wharton	Houston, TX	1,025	NRG	100%
WA Parish	Thompsons, TX	3,649	NRG	100%
Limestone	Jewett, TX	1,689	NRG	100%
South Texas	Bay City, TX	1,136	NRG	44%
Gregory	Gregory, TX	388	NRG	100%

CAISO

CAISO (2,414 MW, Net)				
Name	Location	Capacity	Entity	Ownership %
Midway-Sunset	Fellows, CA	113	NRG	50%
Sunrise	Fellows, CA	586	NRG	100%
Ivanpah	Ivanpah Dry Lake, CA	392	NRG	50%
Long Beach	Long Beach, CA	260	NRG	100%
Watson	Carson, CA	204	NRG	49%
Encina	Carlsbad, CA	859	NRG	100%

WECC

AZ-NV (148 MW, Net)				
Name	Location	Capacity	Entity	Ownership %
Agua Caliente	Dateland, AZ	102	NRG	35%
Saguaro	Henderson, NV	46	NRG	50%

MISO

MISO South (1,263 MW, Net)				
Name	Location	Capacity	Entity	Ownership %
Cottonwood	Deweyville, TX	1,263	NRG	7 Year Lease

PJM

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 %
SMECO	Prince Georges County, MD	78	NRG	100%

NYISO

NYC (1,262 MW, Net)				
Name	Location	Capacity	Entity	Ownership %
Arthur Kill	Staten Island, NY	858	NRG	100%
Astoria	Queens, NY	404	NRG	100%
Central (1,639 MW, Net)				
Name	Location	Capacity	Entity	Ownership %
Oswego	Oswego, NY	1,639	NRG	100%

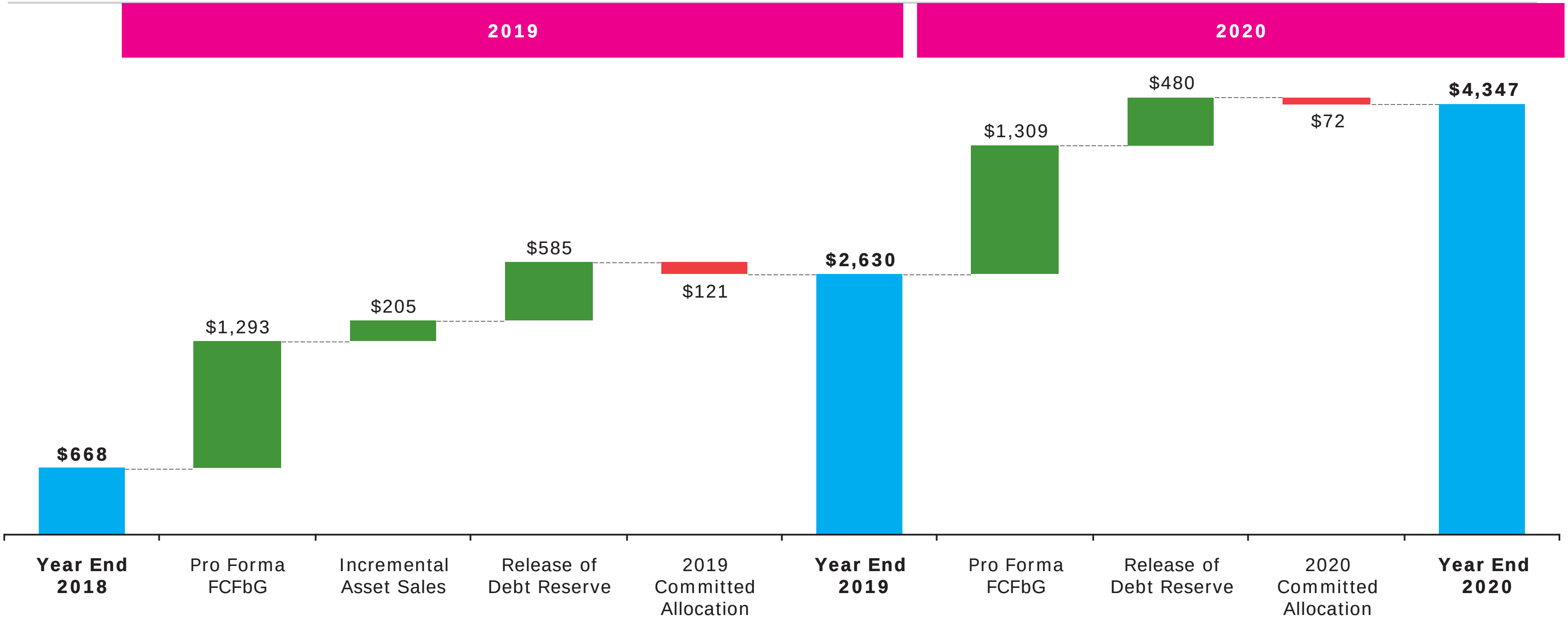
ISO-NE

Connecticut (1,539 MW, Net)				
Name	Location	Capacity	Entity	Ownership %
CT Jets	Connecticut (four sites)	142	NRG	100%
Devon	Milford, CT	133	NRG	100%
Middletown	Middletown, CT	770	NRG	100%
Montville	Uncasville, CT	494	NRG	100%

[1] Excludes International assets

Appendix: Finance

Pro Forma Excess Cash 2018 to 2020 (Analyst Day)



2018 Baseline (mid-point)	$1,000
XOOM	45
Interest savings ($45 + 9)[1]	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

[1-2] See Analyst Day (3/27/2018) Appendix-Finance for footnotes; [3] See Analyst Day (3/27/2018) Appendix-Finance slide 4

Q1 2018 Net Capital Expenditures

($ millions)	Maintenance	Environmental	Growth[1]	Total
Retail	$4	-	$16	$20
Generation				
Gulf Coast	38	-	-	38
East/West[2]	9	-	109	118
Renewables	1	-	142	143
NRG Yield	8	-	10	18
Corporate	4	-	17	21
Total Cash Capital Expenditures	**$64**	**-**	**$294**	**$358**
Other Investments[3]	-	-	62	62
Project Funding, net of fees[4]	-	-	(169)	(169)
Total Capital Expenditures and Growth Investments, net	**$64**	**-**	**$187**	**$251**

[1] Includes cost-to-achieve spend of $17 MM; [2] Also includes International and BETM. 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. (29,989[1] MW)

Renewables (883 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 (2,888 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

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

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

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

[1] Capacity controlled by NRG as of 3/31/2018, 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 3/31/2018

($ millions)

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

NRG Energy, Inc.	
Revolver $2.5 BN due 2018/2021[1]	$ 0
Senior notes due 2022-2028	4,845
Term loan due 2023	1,867
Tax exempt bonds due 2038-2045	465
Capital Lease	4
Total	**$ 7,181**

Retained

Conventional Financings	
Other non-recourse debt	$ 6

Midwest Generation	
Capacity Monetization/ Operating leases[2]	$ 132

Renewables	
Ivanpah Promissory Note and Project financing due 2033 and 2038	$ 1,140
Resi Solar	$30

Asset Sales to be Completed

Agua Caliente	
Project financing due 2037	$ 815
Borrower 1 due 2038	86

Other Renewables Financings	
Project financings	$ 72

Announced Asset Sales

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

NRG Yield Operating LLC	
Revolver $495 MM due 2019[3]	$ 75
Senior Notes due 2024	500
Senior Notes due 2026	350

Yield Project Debt	
Conventional Term loans due 2023	$ 982
Thermal Senior secured notes due 2025 and 2031	$208
Renewable Project Financings	$3,291

Renewables Financings	
Project financings	$ 613

Carlsbad Energy	
Term Loan	$ 475

Note: Debt balances exclude discounts and premiums
[1] $922 MM LC's issued and $1,614 MM Revolver available at NRG; [2] Excludes the present value of lease payments (9.1% discount rate) for Midwest Generation operating lease of $97 MM; this lease is guaranteed by NRG Energy, Inc.; [3] $66 MM of LC's were issued and $354 MM of the Revolver was available at NRG Yield

Recourse / Non-Recourse Debt

($ millions)	3/31/2018	12/31/2017	9/30/2017	6/30/2017
Recourse Debt				
Term Loan Facility	$ 1,867	$ 1,872	$ 1,876	$ 1,881
Senior Notes	4,845	4,845	5,449	5,449
Tax Exempt Bonds	465	465	465	455
Revolver	-	-	-	-
Capital Lease	4	4	6	6
Recourse Debt and Capital Lease Subtotal	**$ 7,181**	**$ 7,186**	**$ 7,796**	**$ 7,791**
Non-Recourse Debt				
Total NRG Yield[1,2]	$ 6,038	$ 6,083	$ 5,901	$ 5,983
Renewables (including capital leases)[2]	2,756	2,783	2,854	2,811
Conventional	613	586	587	546
Non-Recourse Debt Subtotal	**$ 9,407**	**$ 9,452**	**$ 9,342**	**$ 9,340**
Total Debt	**$ 16,588**	**$ 16,638**	**$ 17,138**	**$ 17,131**

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

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
Transaction Fees (estimate)	(60)
Total Proceeds	**$2,922**

[1] Excludes working capital and other customary purchase price adjustments

Appendix:
Reg. G Schedules

Reg. G: Q1 2018 Free Cash Flow before Growth

($ millions)		YTD 3/31/2018
Adjusted EBITDAR	**$**	**554**
Less: EME operating lease expense		(5)
Adjusted EBITDA	**$**	**549**
Interest payments		(187)
Income tax		-
Collateral / working capital / other		(5)
Cash Flow from Operations (continuing operations)	**$**	**357**
Gain on Sale of Land		3
Return of capital from equity investments[1]		2
Cost-to-Achieve[2]		22
Collateral		(163)
Adjusted Cash Flow from Operations	**$**	**221**
Maintenance capital expenditures, net		(64)
Environmental capital expenditures, net		-
Distributions to non-controlling interests		(50)
Consolidated Free Cash Flow before Growth	**$**	**107**
Less: FCFbG at Non-Guarantor Subsidiaries[3]		(15)
NRG-Level Free Cash Flow before Growth	**$**	**92**

[1] Represents cash distributions to NRG from equity investments, net of contribution to PetraNova; [2] Includes costs associated with the Transformation Plan announced on 7/12/2017; [3] Reflects impact from NRG Yield and other excluded project subsidiaries

nrg

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: First 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
(Loss) / Income from Continuing Operations	**(566)**	**30**	**(536)**	**946**	**(34)**	**-**	**(143)**	**233**
Plus:								
Interest expense, net	-	2	2	1	14	54	92	163
Income tax	-	-	-	-	(6)	(1)	6	(1)
Loss on debt extinguishment	-	-	-	-	-	-	2	2
Depreciation and amortization	43	24	67	28	51	81	8	235
ARO Expense	7	4	11	-	1	1	-	13
Contract amortization	3	-	3	-	-	17	-	20
Lease amortization	(1)	(2)	(3)	-	-	-	1	(2)
EBITDA	**(514)**	**58**	**(456)**	**975**	**26**	**152**	**(34)**	**663**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	6	6	(6)	3	34	(2)	35
Acquisition-related transaction & integration costs	-	-	-	-	-	1	3	4
Reorganization costs	2	2	4	3	-	-	13	20
Deactivation costs	-	3	3	-	-	-	3	6
Loss on sale of business	-	-	-	-	1	-	-	1
Other non-recurring charges	6	4	10	2	(8)	2	10	16
Mark to market (MtM) (gains)/losses on economic hedges	567	13	580	(786)	10	-	-	(196)
Adjusted EBITDA	**61**	**86**	**147**	**188**	**32**	**189**	**(7)**	**549**

[1] Includes International, BETM and generation eliminations

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Appendix Table A-3: First 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	**43**	**(6)**	**37**	**(34)**	**(29)**	**(2)**	**(141)**	**(169)**
Plus:								
Interest expense, net	-	9	9	1	22	75	115	222
Income tax	-	-	-	3	(6)	(1)	-	(4)
Loss on debt extinguishment	-	-	-	-	-	2	-	2
Depreciation and amortization	69	28	97	28	47	77	8	257
ARO Expense	4	3	7	-	-	1	1	9
Contract amortization	3	1	4	1	-	17	-	22
Lease amortization	-	(2)	(2)	-	-	-	-	(2)
EBITDA	**119**	**33**	**152**	**(1)**	**34**	**169**	**(17)**	**337**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	7	6	13	(3)	(4)	13	(1)	18
Acquisition-related transaction & integration costs	-	-	-	-	-	1	-	1
Deactivation costs	-	2	2	-	-	-	-	2
Other non-recurring charges	(1)	-	(1)	-	(1)	3	7	8
Mark to market (MtM) (gains)/losses on economic hedges	(121)	9	(112)	137	(6)	-	-	19
Adjusted EBITDA	**4**	**50**	**54**	**133**	**23**	**186**	**(11)**	**385**

[1] Includes International, BETM and generation eliminations

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Appendix Table A-4: 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-5: 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-6: 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-7: 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

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Appendix Table A-8: XOOM Adjusted EBITDA Guidance: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

($ millions)	**2018**
Net income / (loss)	**44**
Plus:	
Income tax	-
Interest expense, net	-
Depreciation, amortization, Amortization of Contracts and ARO expense	1
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-9: Pro Forma Adjusted EBITDA: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

Reposted 5/3/2018, 3:00 pm ET
2020 Line Items Updated:
GAAP Net Income, Interest Expense, Other Costs

	Pro Forma	
($ millions)	**2018**	**2020**
GAAP Net Income[1]	310	887
Income tax	20	20
Interest Expense	414	374
Depreciation, Amortization, Contract Amortization and ARO Expense	522	522
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	67	67
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.