

# Opportunities for Clean Energy in Natural Gas Well Operations

Kathleen Krah  
National Renewable Energy  
Laboratory (NREL)  
Golden, CO, USA  
[kathleen.krah@nrel.gov](mailto:kathleen.krah@nrel.gov)

Sean Ericson  
National Renewable Energy  
Laboratory (NREL)  
Golden, CO, USA  
[sean.ericson@nrel.gov](mailto:sean.ericson@nrel.gov)

Xiangkun Li  
National Renewable Energy  
Laboratory (NREL)  
Golden, CO, USA  
[xiang.li@nrel.gov](mailto:xiang.li@nrel.gov)

Wonuola Olawale  
Colorado School of Mines  
Golden, CO, USA  
[wonuola.olawale@nrel.gov](mailto:wonuola.olawale@nrel.gov)

Ricardo Castillo  
National Renewable Energy  
Laboratory (NREL)  
Golden, CO, USA  
[ricardo.castillo@nrel.gov](mailto:ricardo.castillo@nrel.gov)

Emily Newes  
National Renewable Energy  
Laboratory (NREL)  
Golden, CO, USA  
[emily.newes@nrel.gov](mailto:emily.newes@nrel.gov)

Jill Engel-Cox  
National Renewable Energy  
Laboratory (NREL)  
Golden, CO, USA  
[jill.engelcox@nrel.gov](mailto:jill.engelcox@nrel.gov)

**Abstract**— The oil and gas industry is increasingly seeking operational improvements to reduce both costs and emissions while improving resilience against electric grid outages. This study describes techno-economic analysis of opportunities for distributed energy generation and storage technologies to support companies' energy cost savings, clean energy, and energy resiliency goals. Specifically, the analysis evaluates solar photovoltaics (PV), distributed wind energy, and battery energy storage at hypothetical upstream well sites in the Marcellus Shale in Pennsylvania, both grid-connected and off-grid. Results indicate opportunity for solar PV to reduce operational costs. Additionally, these technologies reduce the site's consumption of grid electricity and natural gas and thus can help reduce Scope 1 and 2 emissions associated with electricity and natural gas consumption. For each emissions reduction scenario, a cost of avoided emissions was calculated; these values can be compared to internal organizational value placed on emissions reductions, compared to other emissions reduction strategies such as energy efficiency, reducing flaring, and direct carbon capture and sequestration, and compared to existing (albeit limited) U.S. carbon markets such as California's Low Carbon Fuel Standard. Results indicate that the associated costs of emissions reductions via distributed renewables are competitive with these options and markets. The study also explores the ability of these electric clean energy technologies to support site resiliency against utility outages.

**Keywords**—renewable energy, oil and gas, integration, techno-economic optimization, resiliency, emissions

## I. INTRODUCTION

Global demand for energy and petroleum products continues to increase. While petroleum facilitates many functions of modern society, the environmental impacts of burning fossil fuels are becoming increasingly apparent. Significant reductions in emissions are required to limit anticipated global temperature increases [1].

This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Strategic Priorities and Impact Analysis Office. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

Most petroleum-related greenhouse gas (GHG) emissions come from the final consumption of oil and gas products [2]. However, the production, transportation, and refining of oil and gas also contribute significantly to global emissions, estimated at 15% of energy-related [3] and 9% of global [4] GHG emissions. Thus, many companies in the oil and gas sector are setting goals to reduce their carbon footprints and investigating pathways to achieve these goals at least cost. According to BP's chief executive, Bernard Looney, "we have got to change and change profoundly...the world does have a carbon budget, and it is running out fast" [5].

Although various measures can help reduce emissions in oil and gas operations [6], this paper focuses on integration of clean energy generation and storage technologies into natural gas well operations. The analysis considers commercially-available renewable electricity technologies, including solar photovoltaics (PV), distributed wind turbines, and battery energy storage, to reduce electric grid and natural gas consumption and associated costs and emissions at hypothetical case study well sites.

Integrating clean energy into natural gas operations at a scale to make a meaningful impact on industry emissions and profits requires an understanding of which technologies are available and where each technology may be beneficially integrated. Several reports provide broad overviews of where clean technologies may be integrated into renewable operations [5,7], discuss integration of specific technologies [8,9,10,11,12], and discuss integration along the various segments of the supply chain [13,14,15]. Other reports describe current and planned clean energy projects in the oil and gas industry [6,16,17,18]. Finally, several papers examine specific case studies of the benefits of integrating specific technologies at specific sites [19,20,21,22].

It can be challenging for an industry decisionmaker to bridge between high-level overviews and site-specific project discussions to prioritize areas where future investments may most cost-effectively support operational energy goals. This paper is intended to help connect the higher-level analysis of technical opportunities with the more detailed analysis of specific potential projects. The study evaluates the opportunity for solar PV, wind turbines, and battery storage to cost-effectively support natural gas organizations in achieving

operational cost reductions, resiliency goals, and emissions reductions targets at case study natural gas well sites.

## II. METHODOLOGY

### A. Scope and Approach

This analysis evaluates distributed clean energy technologies for use at a hypothetical natural gas well site in Pennsylvania. The case study uses only publicly available data in order to (a) inform general takeaways about opportunities for distributed clean energy technologies to support natural gas operations and (b) to illuminate that although publicly available information does have data gaps, useful insights can still be gained without using proprietary information. Such analysis can help prioritize sites and technologies that appear to offer high potential for cost-effective emissions reductions pathways.

Techno-economic analysis was performed using NREL's Renewable Energy Integration and Optimization (REopt) model [23]. This model considers the site's hourly energy consumption profile, solar and wind resource, electricity and fuel costs, along with distributed energy technology capital costs, operations and maintenance (O&M) costs, and performance. Formulated as a mixed-integer linear program, the objective function identifies the lifecycle cost-optimal mix of candidate technologies, their respective sizes, and dispatch strategies, considering, as applicable, renewable energy and/or emissions reductions targets. For this analysis, REopt was used to evaluate the techno-economic potential of solar PV, wind turbines, and battery energy storage, to support oil and gas operations in achieving energy goals including cost savings, resiliency, and emissions reductions, relative to a base case scenario of just purchasing grid electricity or a natural gas generator:

- **Energy cost savings:** First, REopt was allowed to cost-optimally size each technology. Electric generation technologies (solar PV, wind turbines, and battery energy storage) were co-optimized, due to the temporal component of solar and wind resource.
- **Emissions reductions:** Next, the cost per ton carbon dioxide equivalent (tCO<sub>2</sub>e) to achieve 20%, 40%, 60%, 80%, and 100% emissions reductions was quantified. Although most U.S. states do not currently have a carbon market in place, the cost of carbon emissions reductions estimates can be used to inform organizational decisions around environmental impacts of operations. In some cases, industry is placing its own internal value on carbon emissions reductions and these results could be used to inform corporate decision-making independent of government policy.
- **Resiliency:** Finally, the ability of the electric technologies to support the site in sustaining operations through an electric utility outage was evaluated against conventional backup generation options for resiliency.

Note that emissions considered in this analysis fall into the categories of Scope 1 emissions, emissions produced from sources owned or controlled by the company, and Scope 2 emissions, emissions created by another entity feeding into the company's operations (such as the electric utility). Scope 3 emissions, those directly tied to the company's value chain

(including customers' consumption of fuels) were not the focus for this analysis. However, this analysis does not cover *all* Scope 1 and 2 emissions; the paper focuses on opportunities for clean energy technologies to support natural gas well operations, but other measures, not included, such as energy efficiency, reduced flaring, and carbon capture and sequestration (CCS), can also support efforts to reduce Scope 1 and 2 emissions. Additionally, this analysis does not consider future decreases in electric grid emissions rates; emissions reduction costs per tCO<sub>2</sub>e described in this paper apply to year 1 emissions reductions.

### B. Case Study Site Overview

The case study considers a hypothetical region of natural gas wells in the Marcellus Shale in southwestern Pennsylvania, selected for analysis. In particular, a hypothetical area of 23 electrically-interconnected wells covering approximately 1.3 square miles was evaluated. A sensitivity study was performed evaluating these wells under two scenarios: grid-connected electricity or off-grid power by natural gas generator.

Table I shows estimated power requirements of the three phases of well development and production, based on data compiled from [24]. Because pad preparation and drilling and hydraulic fracturing only last a short duration (days) relative to actual natural gas production (decades) and require a significantly different electrical power than the production phase, the analysis of clean energy technology opportunities focused on the production phase. The analysis assumes a flat electrical load across the 23 wells throughout the production phase; in reality, electric requirements may vary over time due to changes in operations and maintenance.

For the grid-connected scenario, a likely electric utility was identified based on territory. A likely utility rate was identified based on distribution service rate descriptions [25] and a screening of over 50 regional suppliers [26]. The assumed cost of electricity is relatively low with an energy charge of \$0.05/kWh and a monthly demand charge of \$4.357/kW. For the off-grid scenario, the site is assumed to generate electricity from natural gas costing \$4.832/MMBTU [27].

TABLE I. ELECTRIC CONSUMPTION FOR WELL PHASES

	Power [kW] for 23 Neighboring Wells	Duration of Phase	Total Energy Consumption [GWh] for 23 Neighboring Wells
Pad Preparation & Drilling	436,167	21 days	219.8
Fracturing	28,957	6 days	4.2
Production	5,737	30-50 years	1,505

### C. Techno-Economic Assumptions

Table II summarizes additional techno-economic assumptions for the case study technologies. The analysis assumes direct ownership by the organization operating the wells over the 25-year analysis period [28], with a discount rate of 5% based on a screening of oil and gas companies' discount rates and an inflation rate of 2.5% [Error! Bookmark not defined.].

TABLE II. TECHNO-ECONOMIC ASSUMPTIONS

	Technologies					
	<i>Electric Grid</i>	<i>Natural Gas Generators</i>	<i>Backup Diesel Generators</i>	<i>Solar PV</i>	<i>Wind Turbines</i>	<i>Battery Storage (Lithium-ion)</i>
Heat rate or renewable resource	N/A	8,500 BTU/kWh	8,500 BTU/kWh	Typical Meteorological Year (TMY3) weather file from the National Solar Radiation Database (NSRDB) [29]	AWS Truepower database [30]	N/A
Capital costs	None	\$1,500/kW	\$1,200/kW	\$1,075/kW-DC [ <b>Error! Bookmark not defined.</b> ]	\$3,450/kW [31,32]	\$420/kWh + \$840/kW [33,34]
Incentives	None	None	None	26% ITC, 5-year MACRS depreciation [35]	5-year MACRS depreciation [35]	26% ITC, 5-year MACRS depreciation [35]
O&M costs	None	Fixed: \$165/kW/year; Variable: \$0.0012/kWh	Fixed: \$100/kW/year; Variable: \$0.0008/kWh	\$13/kW-DC/year [ <b>Error! Bookmark not defined.</b> ]	\$40/kW/year [31,32]	Replacement in Year 10: \$200/kWh + \$410/kW
Fuel costs	Utility rate described in text	\$4.832/MMBTU [27]	\$22.082/MMBTU [27]	None	None	None
Fuel cost escalation rate	2.55%/year [27]	2.55%/year [27]	2.73%/year [27]	None	None	None
Carbon emissions	756.93 lbCO <sub>2</sub> e/MWh [36]	117 lbCO <sub>2</sub> e/MMBTU [37]	N/A (backup only)	None	None	None
Other	Net metering limit: 3 MW [35]  Outage event durations [38]: - Major events: 1 day - Non-major events: 2 hours	None	None	Tilt = latitude  DC-AC ratio: 1.2	Installed capacity density: 30 acres/MW	AC-AC roundtrip efficiency: 89.9% [39]  Minimum state of charge: 20% [39]

#### D. Caveats

The following caveats apply to this analysis:

- The analysis is dependent on inputs and assumptions described throughout this paper.
- The analysis is based on publicly available data; analysis of higher-resolution site-specific data may impact results.
- Results of the hypothetical case studies should not be taken to be suggestive of the economics of these clean energy technologies at any actual wells; technical and economic feasibility of clean energy technologies at a particular site should be assessed before making investment or implementation decisions.
- Analysis considers loads, resource, and generation at hourly intervals and does not capture intra-hour variability.
- Analysis assumes all 23 gas wells are electrically interconnected and, for the grid-connected examples, sited behind a single meter.
- Land available for distributed generation and/or storage were assumed to be unlimited; limitations to technology footprint could impact the feasibility of the solutions suggested in this analysis.

#### III. RESULTS

This section discusses the cost-optimal distributed technology solutions to help the case study sites minimize costs, be resilient to grid outages (for the grid-connected case study), and reduce carbon emissions.

##### A. Cost-Optimal

For both grid-connected and off-grid scenarios, the model recommended 7.4 MW-DC of solar PV as the cost-optimal system size to minimize the lifecycle cost of energy at the site. Table III compares the base case (no PV, wind turbines, or battery storage) system and economics for each scenario with the cost-optimal system. For the grid-connected wells, the base case is made up entirely of electric grid purchases. For the off-grid wells, the base case includes the cost of the natural gas generator and natural gas.

As shown in Table III, which presents selected REopt results for the scenario minimizing lifecycle cost of energy for the case study sites, such a solar PV system would help reduce lifecycle costs of electricity powering grid-connected or off-grid wells by \$100k and \$500k, respectively. Although this is a relatively small percentage cost savings relative to overall system costs, the PV system can also support the site in achieving clean energy goals. Though the model could have selected to build wind and/or battery storage, it did not appear cost effective to do so, indicated in Table III by the rows with no system size listed.

TABLE III. RESULTS – COST-OPTIMAL SIZING

	Grid-Connected Wells		Off-Grid Wells	
	Base case	Cost optimal	Base case	Cost optimal
PV capacity [MW-DC]	-	7.4	-	7.4
Wind capacity [MW-AC]	-	-	-	-
Battery energy capacity [MWh]	-	-	-	-
Battery inverter capacity [MW]	-	-	-	-
Natural gas generator capacity [MW]	-	-	5.7	5.7
Capital costs [\$M]	-	5.1	8.6	13.7
Annualized electricity purchase or conventional generation costs [\$M]	3.7	3.2	2.8	2.4
Levelized cost of energy [\$ /kWh]	0.074	0.074	0.094	0.093
Total lifecycle costs [\$M]	52.5	52.4	66.6	66.1
Net present value [\$M]	-	0.1	-	0.5

### B. Carbon Emissions Reductions

Finally, the cost of reducing the carbon emissions associated with the electricity used to power the wells was evaluated. For the grid-connected wells, these are considered Scope 2 emissions. For the off-grid wells, these are considered Scope 1 emissions. The least-cost system to reduce emissions from electricity generation by 20%, 40%, 60%, 80%, and 100% was identified and the marginal cost of emissions reductions was calculated.

For the grid-connected wells, two scenarios were evaluated. In one scenario, the site was allowed to claim emissions reductions credit for excess renewable electricity exported to the grid, based on its net emissions footprint. In the other scenario, the site was not allowed to claim this emissions credit for exported renewable generation. Because the off-grid site is assumed to not have an outlet to channel any excess renewable generation not captured by the battery, any excess renewable generation at this site would be curtailed and thus unable to receive any emissions credit.

**Error! Reference source not found.** compares the results for the three scenarios assessed. Tables IV and V provide more details about the technology selection and sizing as well as the costs and emissions for these three scenarios.

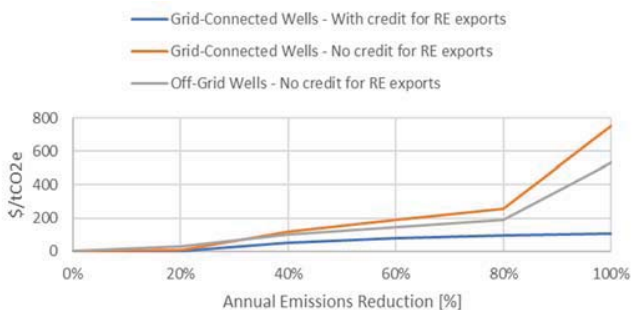


Fig. 1. Results – Cost of Emissions Reductions for various penetrations of renewables.

Note that the 20%, 40%, 60%, 80%, and 100% emissions reductions scenarios have a negative net present value, indicating that achieving these scenarios is more expensive than the base case scenario. Although a smaller PV system (7.4 MW-DC) is able to offset its costs with savings from avoided grid purchases, larger PV systems required to achieve higher emissions reductions end up exporting renewable generation that is not compensated because the system capacity exceeds the net metering limit. (A higher net metering limit could yield different sizing recommendations and improved economics.)

The last row of the results tables indicates the cost of carbon that would be required to make the system cost effective. This cost of carbon could be compared to existing external carbon markets [40], and/or can be used to help oil and gas companies prioritize identified options for emissions reductions based on cost.

As highlighted by the recommended system sizes in Tables IV and V, results suggest that solar PV is the most cost-effective technology for this hypothetical site to achieve emissions reductions targets, especially if renewable exports can be netted against purchases. Keeping in mind that 7.4 MW-DC of PV is cost optimal even without considering some potential cost of carbon, achieving 20% emissions reductions is relatively inexpensive and only increases the total system lifecycle costs by <1%, with a very low cost of emissions reductions of \$7.20/tCO<sub>2e</sub>.

Without net emissions accounting, renewable generation must be consumed onsite, rather than counting exported renewable electricity towards clean energy targets. In this accounting scenario, wind energy and/or battery storage are recommended to achieve emissions reductions targets. Wind energy supplements solar PV generation, especially because wind energy continues, and is often stronger, through nighttime hours than daytime hours. Battery storage helps utilize excess onsite generation to serve loads not coincident with solar or wind resource. However, the costs of wind turbines and battery storage increase the cost of emissions reductions to ~\$120-250/tCO<sub>2e</sub> to achieve 40-80% emissions reductions. The marginal cost of emissions reductions increases even more to completely eliminate the carbon emissions footprint from electricity purchases. This last 20% is the most expensive to capture because it requires such high capacities, particularly of battery storage, because marginal increases in clean energy capacities yield decreasing margins of cost savings and of emissions reductions due to lower utilization.

Because the modeled natural gas generator produces more carbon emissions than the Pennsylvania grid (25.0 ktCO<sub>2e</sub> vs. 19.0 ktCO<sub>2e</sub> in the base case, per Tables V and IV, respectively, slightly more renewables are required for the off-grid wells to achieve the same percentage of emissions reductions as the grid-connected wells. The \$/tCO<sub>2e</sub> cost of emissions reductions for the off-grid site is more expensive than the grid-connected site with net emissions accounting, but less expensive than the grid-connected site without net emissions accounting (see last row of Tables IV and V). However, similar trends in costs can be observed, namely a relatively inexpensive path to the first 20% emissions reductions and a relatively expensive path to close the gap on the last 20% emissions reductions.

TABLE IV. RESULTS – GRID-CONNECTED EMISSIONS REDUCTIONS

	Base case	Cost optimal	Annual % Emissions Reduction - With Net Emissions Accounting					Annual % Emissions Reduction - Without Net Emissions Accounting				
			20%	40%	60%	80%	100%	20%	40%	60%	80%	100%
PV capacity [MW-DC]	-	7.4	10.0	19.9	29.9	39.9	49.9	10.5	13.7	21.8	35.7	63.4
Wind capacity [MW-AC]	-	-	-	-	-	-	-	-	6.0	9.1	10.3	30.5
Battery energy capacity [MWh]	-	-	-	-	-	-	-	-	-	25.5	69.3	282.3
Battery inverter capacity [MW]	-	-	-	-	-	-	-	-	-	3.8	8.5	7.3
Capital costs [\$M]	-	5.1	6.9	13.7	20.6	27.4	34.3	7.2	23.9	48.0	78.4	216.5
Annualized electricity purchase costs [\$M]	3.7	3.2	3.1	2.8	2.6	2.5	2.4	3.1	2.4	1.6	0.9	-
Levelized cost of energy [\$ / kWh]	0.074	0.074	0.074	0.082	0.092	0.103	0.114	0.075	0.092	0.117	0.151	0.359
Total lifecycle costs [\$M]	52.5	52.4	52.7	57.9	65.0	72.7	80.8	52.9	65.4	82.9	107.2	254.4
Net present value [\$M]	-	0.1	(0.2)	(5.5)	(12.5)	(20.2)	(28.4)	(0.4)	(12.9)	(30.4)	(54.7)	(201.9)
Annual emissions [ktCO <sub>2</sub> e]	19.0	16.2	15.2	11.4	7.6	3.8	-	15.2	11.4	7.6	3.8	-
Annualized cost of emissions reductions [\$ / tCO <sub>2</sub> e]	-	(2.1)	4.1	50.8	77.6	94.0	105.8	7.2	120.2	189.3	255.3	753.3

TABLE V. RESULTS – OFF-GRID EMISSIONS REDUCTIONS

	Base case	Cost optimal	Annual % Emissions Reduction				
			20%	40%	60%	80%	100%
PV capacity [MW-DC]	-	7.4	11.1	16.0	22.8	36.4	60.3
Wind capacity [MW-AC]	-	-	-	4.5	8.4	10.1	31.0
Battery energy capacity [MWh]	-	-	-	8.8	29.5	70.1	285.5
Battery inverter capacity [MW]	-	-	-	1.5	4.3	8.6	7.7
Natural gas generator capacity [MW]	5.7	5.7	5.7	5.3	4.7	3.8	-
Capital costs [\$M]	8.6	13.7	16.3	33.5	55.5	84.2	216.8
Annualized conventional generation costs [\$M]	2.8	2.8	2.2	1.7	1.1	0.6	-
Levelized cost of energy [\$ / kWh]	0.094	0.093	0.097	0.114	0.138	0.170	0.359
Total lifecycle costs [\$M]	66.6	66.5	68.5	81.0	97.7	120.4	254.4
Net present value [\$M]	-	0.1	(1.9)	(14.4)	(31.1)	(53.8)	(187.8)
Annual emissions [ktCO <sub>2</sub> e]	25.0	25.0	20.0	15.0	10.0	5.0	-
Annualized cost of emissions reductions [\$ / tCO <sub>2</sub> e]	-	-	27.1	102.5	147.0	190.8	533.3

### C. Resiliency

For the grid-connected well site case study, onsite clean energy technologies could support a site's resiliency goals by facilitating continued operations in the case of an electric grid outage. A major (1 day) and non-major (2 hours) outage event were each modeled with two alternatives to facilitate sustained operations through the grid outage: a backup diesel generator or clean energy technologies that can provide backup. These modeled outages are considered representative, though in reality the outage could occur at any time. To be conservative, modeled outages were assumed to occur at night during a period of no solar resource to increase the probability that the recommended system would be able to survive outages of similar length regardless of when they occur. The model requires that either the backup generator or a renewable energy/battery system can sustain the site's full load for the entire modeled outage.

As shown in the results presented in Table VI, the combination of PV and battery appears more cost-effective than a backup diesel generator for shorter outage durations because these technologies can also help reduce grid purchases throughout normal operations. Although the modeled grid outage occurs at night when solar power is not available, the solar PV is used to charge up the battery with enough energy to survive the grid outage and both technologies can help reduce electricity costs throughout the rest of the year as well.

As outages become longer, significant battery storage is required in order to power the site's operations through the night. In this case, the backup generator appears a more cost-effective source of long-term backup power. Note that in the renewable backup scenario for the major event, REopt chose to install a battery with very large energy capacity rather than reducing the battery capacity in favor of wind turbines, which continue to provide power through the night. This is likely due

to a combination of relative capital costs, low wind resource in general, and variability of wind resource leading to low resource during the modeled grid outage.

Note that the resiliency value of renewables was not assessed at the off-grid wells case study because natural gas is presumed to be a more reliable source of energy and less likely than grid electricity to experience hours-long or days-long outages of supply. For a detailed study of the reliability of natural gas and diesel backup power, see [41].

TABLE VI. RESULTS – RESILIENCY DURING GRID OUTAGES

	Major Event (1 day)		Non-Major Event (2 hours)	
	<i>Backup diesel case</i>	<i>RE case</i>	<i>Backup diesel case</i>	<i>RE case</i>
PV capacity [MW-DC]	-	18.2	-	11.6
Wind capacity [MW-AC]	-	-	-	-
Battery energy capacity [MWh]	-	173.8	-	14.7
Battery inverter capacity [MW]	-	5.7	-	5.7
Backup diesel generator capacity [MW]	5.7	-	5.7	-
Capital costs [\$M]	6.9	74.7	6.9	16.8
Annualized electricity purchase costs [\$M]	3.7	2.5	3.7	2.9
Total lifecycle costs [\$M]	70.4	114.2	70.0	60.9
Net present value [\$M]	(17.9)	(61.7)	(17.6)	(8.5)

#### IV. CONCLUSIONS

This paper describes the potential for solar PV, distributed wind energy, and battery storage to help reduce Scope 1 and 2 emissions from electricity and fuel consumption at hypothetical upstream wells. These technologies, and solar PV in particular, appear to have high potential to reduce emissions cost-effectively, but challenges include low cost of electricity and the flat load that makes reducing demand charges challenging. Additionally, siting requirements may pose a challenge, both from a land availability and ownership perspective, along with potential electrical integration upgrades required to facilitate high penetrations of behind-the-meter or off-grid renewables. However, if located onsite, these technologies can also help sites become more resilient to electric grid outages, which could become particularly important if natural disasters become more frequent and/or extreme in their impacts.

Locational factors such as solar and wind resource and cost of electricity (grid purchases or natural gas generation) will likely impact the economic feasibility of solar PV and wind energy for industrial applications such as natural gas wells. Although a locational sensitivity was not conducted in this case, it is important to note that the solar resource in Pennsylvania is moderate relative to the rest of the United States. It is expected that an upstream operation in southern California, for example, which has both a high solar resource and a carbon market would have results that favor a larger PV system in the cost optimal and emissions reduction cases. This is a potential topic of future analysis.

Similar analysis could be completed for other oil and gas sites, such as midstream and downstream locations, and for other industrial applications where electricity and/or fuel consumption requirements are high, thus offering significant opportunity for high-impact emissions reductions.

Although this analysis focused on distributed clean energy generation and storage alternatives to grid electricity and natural gas purchases to power operations, other opportunities to reduce operational emissions include CCS, reducing flaring, and purchasing carbon offsets. The costs of emissions reductions presented in this report should be considered in the context of the costs of these additional options to help organizations prioritize energy pathways; a comprehensive energy plan likely includes a mix of measures.

#### ACKNOWLEDGMENT

The authors acknowledge Paul Spitsen and Sarah Garman of the U.S. Department of Energy (DOE) for their support of this work through the Joint Institute for Strategic Energy Analysis (JISEA). Additionally, the authors are grateful for the expertise and feedback provided by partner organizations involved in JISEA's Clean Power in Oil & Gas Consortium. Valuable reviews, in addition to those listed above, were provided by Emma Elgqvist and Dylan Cutler (NREL). Additionally, the authors are grateful for the support provided through Colorado School of Mines' Advanced Energy Systems graduate program.

This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Strategic Priorities and Impact Analysis Office. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

#### REFERENCES

- [1] IPCC, "Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty," Ed: V. Masson-Delmotte, P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield, 2018.
- [2] EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2016," 2018.
- [3] IEA, "The Oil and Gas Industry in Energy Transitions," 2020.
- [4] P. Gargett, S. Hall, and J. Kar, "Toward a net-zero future: Decarbonizing upstream oil and gas operations," McKinsey, 2019.
- [5] S. Mufson, "BP, one of the world's biggest oil-and-gas companies, says it is turning over a green leaf," *Washington Post*, Feb. 12, 2020.
- [6] E. Shojaeddini, S. Naimoli, S. Ladislav, and M. Bazilian, "Oil and gas company strategies regarding the energy transition," *Progress in Energy*, vol. 1, no. 1, pp. 1-19. Jul. 2019.

- [7] S. Ericson, J. Engel-Cox, and D. Arent, "Approaches for Integrating Renewable Energy Technologies in Oil and Gas Operations," NREL, 2019.
- [8] M. Halabi, A. Al-Qattan, and A. Al-Otaibi, "Applications of Solar Energy in the Oil Industry--Current Status and Future Prospects," *Renewable and Sustainable Energy Reviews*, vol. 43, pp. 296-314, Mar. 2015.
- [9] J. Wang, J. O'Donnell, and A. Brandt, "Potential Solar Energy Use in the Global Petroleum Sector," *Energy*, vol. 118, pp. 884-892, Jan. 2017.
- [10] P. Kurup and C. Turchi, "Initial Investigation into the Potential of CSP Industrial Process Heat for the Southwest United States," NREL, 2015.
- [11] A. Elson, R. Tidball, and A. Hampson, "Waste Heat to Power Market Assessment," ICF International, 2015.
- [12] Wood Mackenzie, "Why powering oil and gas platforms with renewables makes sense," 2019.
- [13] E. Worrell and C. Galitsky, "Energy Efficiency Improvements in the Petroleum Refining Industry," 2005.
- [14] E. Worrell, M. Corsten, and C. Galitsky, "Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An ENERGY STAR Guide for Energy and Plant Managers," EPA, 2015.
- [15] J. Greenblatt, "Opportunities for Efficiency Improvements in the U.S. Natural Gas Transmission, Storage and Distribution System," LBNL, 2015.
- [16] BP, "Advancing the Energy Transition," 2020.
- [17] M. Zhong and M. Bazilian, "Contours of the Energy Transition: Investment by International Oil and Gas Companies in Renewable Energy," *The Electricity Journal*, vol. 31, no. 1, pp. 82-91, Jan. 2018.
- [18] Eni, "Eni for 2018 - Path to Decarbonization," Accessed: 2020. [Online]. Available: <https://www.eni.com/assets/documents/EniFor-2018-reduction-of-GHG-emissions.pdf>
- [19] W. He, K. Uhlen, M. Hadiya, Z. Chen, G. Shi, and E. del Rio, "Case Study of Integrating an Offshore Wind Farm with Offshore Oil and Gas Platforms and with an Onshore Electrical Grid," *Journal of Renewable Energy*, 2013.
- [20] S. Xin, H. Liang, B. Hu, and K. Li, "Electrical Power Generation From Low Temperature Co-Produced Geothermal Resources at Huabei Oilfield," in *Thirty-Seventh Workshop on Geothermal Reservoir Engineering*, Stanford, CA, USA, 2013.
- [21] A. Endurthy, A. Kialashaki, and Y. Gupta, "Solar Jack Emerging Technologies Technical Assessment," Pacific Gas and Electric Company, 2013.
- [22] M. Korpas, L. Warland, W. He, and J.O.G. Tande, "A Case-Study on Offshore Wind Power Supply to Oil and Gas Rigs," *Energy Procedia*, vol. 24, pp. 18-26, 2012.
- [23] D. Cutler, D. Olis, E. Elgqvist, X. Li, N. Laws, N. DiOrio, A. Walker, and K. Anderson, "REopt: A Platform for Energy System Integration and Optimization," NREL, 2017.
- [24] D. Moeller and D. Murphy, "Net Energy Analysis of Gas Production from the Marcellus Shale," *BioPhysical Economics and Resource Quality*, vol. 1, no. 5, 2016.
- [25] West Penn Power Company, "Supplement No. 60, Electric Pa P.U.C. No. 40 - Electric Service Tariff," Reading, PA, USA, July 1, 2019. Accessed: 2020. [Online]. Available: <https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/PA/tariffs/WPP-Tariff-40-Supp-60.pdf>
- [26] Pennsylvania Public Utility Commission, "PA Power Switch," Accessed: 2019. [Online]. Available: <https://www.papowerswitch.com/>
- [27] EIA, "Annual Energy Outlook 2020," 2020.
- [28] NREL, "2019 Annual Technology Baseline," 2019.
- [29] NREL, "National Solar Radiation Data Base (NSRDB)," 2018.
- [30] AWS, "AWS Truepower Database," Accessed: 2020.
- [31] A.C. Orrell and E.A. Poehlman, "Benchmarking U.S. Small Wind Costs," PNNL, 2017.
- [32] A. Orrell, D. Prezioso, N. Foster, S. Morris, and J. Homer, "2018 Distributed Wind Market Report," PNNL, 2018.
- [33] Wood Mackenzie, "U.S. Energy Storage Monitor: Q3 2019 Full Report," Wood Mackenzie Power & Renewables and the Energy Storage Association (ESA), September 2019.
- [34] Lazard, "Lazard's Levelized Cost of Storage Analysis - Version 4.0," 2018.
- [35] NC Clean Energy Technology Center, "Database of State Incentives for Renewables & Efficiency (DSIRE)," Accessed: 2020.
- [36] EPA, "Emissions & Generation Resource Integrated Database (eGRID) 2018 v.2," 2020.
- [37] EPA, "Greenhouse Gas (GHG) Emissions," Accessed: 2020. [Online]. Available: <https://www.epa.gov/ghgemissions>
- [38] EIA, "Annual Electric Power Industry Report, Form EIA-861 detailed data files - Final 2018 data," 2019.
- [39] C. Patsios, B. Wu, E. Chatzinikolaou, D.J. Rogers, N. Wade, N.P. Brandon, and P. Taylor, "An integrated approach for the analysis and control of grid connected energy storage systems," *Journal of Energy Storage*, vol. 5, pp. 48-61, Feb. 2016.
- [40] California Air Resources Board, "Low Carbon Fuel Standard: Data Dashboard," Accessed: 2020. [Online]. Available: <https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard>
- [41] S. Ericson and D. Olis, "A Comparison of Fuel Choice for Backup Generators," NREL, 2019.