IRENA
International Renewable Energy Agency

SMART GRIDS AND RENEWABLES:

A COST-BENEFIT ANALYSIS GUIDE FOR DEVELOPING COUNTRIES

Annex

Contents

Annex I

Exercise 1:
Ruritania Case Study: Distribution Automation Programme with no Predefined Renewables Goal Approach

In contrast to the case study on Ruritania presented in the main report, this example modifies the original assumptions to eliminate the preexisting renewable energy deployment goal to show how the CBA methodology works. Recall that in this case, we follow the methodology shown on the right half of the flowchart in Figure 3A.

PROPOSED SMART GRID PROJECT DESCRIPTION

The basic country information remains the same as originally introduced in Chapter 3 except that the 20% renewables goal is eliminated. As in the original Ruritania example, the country begins with a mix of coal and natural gas generation powering its 10 GW of peak load; other assumptions remain the same, unless stated otherwise below.

This case study considers the deployment of DA systems on 50% of the nation's feeders over the first 5 years of the project period. While a DA system may serve many purposes, in this example, it provides only automated voltage and VAR control for volt-VAR optimization (VVO).

Necessary Assumptions

This example case study is based on many simplifying assumptions. We use estimates and industry average values for various system enhancements. When performing a CBA on an actual electricity system, an engineering study of existing feeders and planned upgrades would be needed. Additional benefit-specific and cost-specific assumptions are listed within Table AR4 and Step 5, respectively whilst the primary assumptions made, are as follows:.

- A societal perspective is taken for this CBA. The assumed discount rate is 8%, and annual inflation is assumed to be 3%, as before.
- At the start of the project, the electric system includes 40 MW of distributed PV, which provides 0.2% of the country's annual electricity.
- Under this CBA approach, the baseline includes an estimate of how much renewable energy of a given type could be deployed in the business-as-usual scenario (without needing the proposed smart grid project). Here we assume that an engineering analysis has shown that enough distributed PV could be installed to account for 15% of Ruritania's annual electricity use without the proposed DA system. The costs and benefits of any distributed PV expected to be installed above that 15% will be incorporated into the CBA. We assume that over the first 15 years of this project, distributed PV will rise to account 20% of annual electricity use. The costs and benefits of the PV systems that supply the additional 5% of annual electricity use will be included in the CBA. These PV systems have a total capacity of 1,983 MW (compared to the year-15 peak electricity demand of 20,000 MW). The CBA will only consider the initial period of 15 years, and does not capture the benefits of PV installed after year 15. While it would be possible to install additional PV after year 15, this project does not assume that any more is installed.

APPLICATION OF METHODOLOGY

STEP 1: DEFINE PROJECT

- Install DA systems on 10% of the nation's feeders each year for 5 years.
- The DA systems will be capable of automatic voltage and VAR optimization.
- The project term is 30 years. (A longer term is used to allow the CBA to capture the benefits of PV installed in year 15.)
- The CBA takes a societal perspective, with stakeholders being the utility, electricity consumers and society at large.

Because the country has no preexisting renewables goal, this case study uses the No Predefined Renewables Goal approach: Renewable energy installations enabled by the project are included as benefits in the CBA. Some expansion of generation, transmission, and distribution to meet growing load is also part of the baseline.

STEP 2: IDENTIFY FUNCTIONS

Table AR1 shows a matrix mapping the DA resource to the smart grid functions it serves. In general, DA systems have a broad array of functions; Table AR1 checks only the function related to automated voltage control.

Table AR1: Mapping DA to its functions

Functions	Distribution Automation
Fault current limiting	
Wide-area monitoring and visualization	
Dynamic capability rating	
Flow control	
Adaptive protection	
Automated feeder switching	
Automated voltage and VAR control	✓
Diagnosis and notification of equipment condition	
Enhanced fault protection	
Real-time load measurement and management	
Real-time load transfer	
Customer electricity-use optimization	

STEP 3: MAP FUNCTIONS TO BENEFITS

Table AR2 shows how the smart grid function identified in Table AR1 maps to benefits. Note that because this case study uses the No Predefined Renewables Goal approach, this table contains rows for enabled wind and solar generation.

The improved feeder voltage profiles associated with automated voltage and VAR control can enable higher levels of distributed PV. Hence, we have checked "enabled solar generation" as a potential benefit in Table AR2. We must now expand the CBA to capture any benefits of enabled solar. This is done by creating a benefits table for distributed PV and looking for benefits it may activate, as shown in Table AR3.

By considering the value of the DR programme on additional renewables deployment, the following benefits should also be considered:

- Reduced generation capacity investments;
- Reduced CO_2 emissions;
- Reduced SOx, NOx, and PM-10 emissions;
- Reduced fuel costs.

Table AR2: Mapping functions to benefits

Benefits	Automated voltage and VAR control
Optimized generator operation	
Reduced generation capacity investments	
Reduced ancillary service cost	
Reduced congestion cost	
Deferred transmission capacity investments	
Deferred distribution investments	
Reduced equipment failures	
Reduced distribution maintenance cost	
Reduced distribution operations cost	
Reduced meter reading cost	
Reduced electricity theft	
Reduced electricity losses	✓
Reduced electricity cost	
Reduced sustained outages	
Reduced major outages	
Reduced restoration cost	
Reduced momentary outages	
Reduced sags and swells	✓
Reduced CO_2 emissions	✓
Reduced SOx, NOx, and PM-10 emissions	✓
Reduced fuel cost	
Reduced wide-scale blackouts	
Enabled wind generation	
Enabled solar generation	✓

Table AR3: Mapping enabled PV to its benefits

Benefits	Distributed PV generation
Optimized generator operation	
Reduced generation capacity investments	✓
Reduced ancillary service cost	
Reduced congestion cost	
Deferred transmission capacity investments	✓
Deferred distribution investments	✓
Reduced equipment failures	
Reduced distribution maintenance cost	
Reduced distribution operations cost	
Reduced meter reading cost	
Reduced electricity theft	
Reduced electricity losses	✓
Reduced electricity cost	✓
Reduced sustained outages	
Reduced major outages	
Reduced restoration cost	
Reduced momentary outages	
Reduced sags and swells	
Reduced CO_2 emissions	✓
Reduced SOx, NOx, and PM-10 emissions	✓
Reduced fuel cost	✓
Reduced wide-scale blackouts	

STEP 4: MONETIZE BENEFITS

Table AR4 shows estimated values, valuation methods, uncertainty levels, and primary beneficiaries of each of the benefits identified in Tables AR2 and AR3. Note that for PV-related benefits, only the benefits of PV installed in year 15 are included because that is the year that the portion of electricity from PV becomes larger than 15%, the level assumed to be possible without the smart grid project. The largest benefits are the reduction in fuel costs due to PV, the reduction in CO_2 emissions due to both PV generation and DA-driven efficiency improvements, and reduced customer electricity costs due to DA voltage optimization. Notably, each of these major benefits accrues to a different stakeholder group.

Qualitative Benefits

This DA program would also have some nonmonetizable benefits. For instance, once the DA hardware and communications systems are in place, it should be possible to extend the system to serve other functions, such as remote and/or automatic operation of switches and monitoring of hardware health. The energy security benefits of the PV generation will also be very valuable in displacing imported fossil fuels. Finally, while this project monetizes the benefits of increased renewables, those benefits are just beginning to come into play in the final half of the project. Further expansion of distributed PV is possible in future years simply by continuing the course set by this project.

Table AR4: Values of benefits

Benefit	Estimated value (million USD)	Estimation basis	Uncertainty level	Primary beneficiary
Reduced generation capacity investments	NPV 40.9	The PV enabled by this project is assumed to have a capacity value of 10%. Installed PV capacity is assumed to grow at a rate of 35% per year to 6,700 MW by the final year. In year 15 of the project, enough PV capacity will be installed to avoid the construction of one 200 MW gas power plant at USD 750/kW, which has a present value of USD 40.9M	Medium	Utility
Deferred transmission capacity investments	0	While PV may reduce the need for additional transmission, in this case, no such reduction is assumed.	Medium	Utility
Deferred distribution investments	0	The PV systems may reduce peak load (thereby reducing required distribution feeder capacity) on some feeders but may also increase it on others. Hence, no monetary value is assumed.	High	Utility
Reduced CO_2 emissions	294/yr, (year 30); NPV 616	Both PV generation and line loss reduction leas to CO_2 reductions. We assume a social cost of carbon of USD 50/ton, and each MWh of conventional generation displaced is assumed to avoid 0.68 tons of CO_2. The savings due to reduced line losses reach USD 294M by year 30	Medium	Society
Reduced SOx, NOx, and PM-10 emissions	NPV 37	Loss reductions and PV generation also lead to reductions in SOx, NOx, and PM-10 emissions. Each MWh produced from coal is assumed to produce 5 kg SOx, 3 kg NOx, and 1 kg PM-10. Reductions in SOx, NOx, and PM-10 are valued at USD 3.15, USD 0.70, and USD 0.20 per kg, respectively. Resulting savings NPVs are USD 32M, USD 4.3M, and USD 409K, respectively.	Medium	Society
Reduced fuel cost	343 (year 30); NPV 736	PV generation displaces coal and gas-fired generation, reducing fuel costs, which are assumed to make up 92% of power production costs (PJM, 2009). PV is estimated to reduce fuel costs in year 30 by USD 343M.	Low	Utility
Reduced electricity cost	94/yr (year 30); NPV 375	Through the DA system's voltage optimization function, customer service voltages are assumed to be reduced to optimal levels, resulting in an average savings of 1.5% on electricity bills for customers on those feeders (Uluski, 2013). Annual savings are USD 94M by year 30.	Medium	Customers
Reduced electricity losses	59.6/yr (year 30); NPV 106	Automated voltage and VAR control is assumed to reduce line losses by 3% on the affected feeders, in line with (NEMA, 2013). Distributed PV is assumed to reduce line losses by an additional 4% by providing power closer to the loads. The total annual benefit is USD 59.5M in year 30.	Low	Utility

STEP 5: QUANTIFY COSTS

The DA project has two subcategories of costs associated with it: initial costs and operating expenses. Capital costs are assumed to be USD 150,000 per feeder based on (NEMA, 2013) and (Neural Energy, 2011). Annual operating expenses are assumed to be 3% of capital costs based on (NEMA 2013) and (Uluski, 2013).

The PV systems have three categories of costs: first costs, operating costs, and indirect costs incurred by the utility to mitigate the intermittency of PV generation. As with the benefits of PV, these costs are only counted after the portion of electricity from PV surpasses 15%, the level possible in the baseline case. Distributed PV costs are assumed to be USD 4000/kW initially, plus USD 20 in O&M per kW each year thereafter. PV capital costs have fallen between 42% and 70% between 2008 and 2014 (IRENA, 2015a). Indirect costs, sometimes called PV integration costs, will be less than usual for this example because the DA system will largely eliminate voltage problems. It is assumed that integration costs will amount to USD 2/MWh produced by PV.

These costs are summarized in Table AR5. All future costs are inflation-adjusted and PV capital costs dominate the expenses.

STEP 6: COMPARE COSTS AND BENEFITS

The current total value of the project benefits is USD 1 910 million, while the current total value of the costs is USD 1 868 million. The benefits exceed the costs only slightly (by USD 43 million, or 2%), so the project is cost-effective but the cost-effectiveness will be highly sensitive to assumptions and uncertainties. Qualitative benefits tip the scale a bit further in the direction of a positive CBA result.

STEP 7: PERFORM SENSITIVITY ANALYSIS

This project installs a large amount of distribution-connected PV and calculates its most valuable benefit, which is the generator fuel displacement in terms of electricity production costs. This makes sense if the PV is mostly utility-owned, but if the PV is mostly customer-owned and the PV is net-metered, the benefit should be calculated in terms of retail electricity costs. In Ruritania, average retail electricity costs of USD 100/MWh are double the production costs of USD 50/MWh. If we change the project from utility-owned PV to customer-owned PV, the value of fuel savings would be zero but the NPV of electricity cost reductions would increase by roughly USD 1 500 million, giving the project a positive NPV of roughly USD 800 million, a very large improvement.

Table AR5: Values of costs

Cost	Estimated NPV (USD)	Estimation basis	Uncertainty level	Payer
DA capital expenditure	127M	USD 150K per feeder at time of installation, spread over first 5 years	Low	Utility
DA operating expenses	58M	USD 6K per feeder per year (3% of capital expenditure)	Low	Utility
PV capital expenditure	1 332M	USD 4,000/kW PV capacity, reduced 4.5% per year due to technology maturation; year 15 only	Low	Utility or private owners
PV operating expenses	313M	USD 20/kW PV capacity per year	Low	Utility or private owners
PV indirect expenses	38M	USD 2/MWh produced from PV	Medium	Utility

In practice, many PV systems are owned by third parties rather than by the utility or electricity end users. In this case, the total benefits are contract-dependent and must be calculated carefully. If the third party sells PV-generated electricity to end users, the price is likely somewhat below retail but above utility production costs. Hence, the project NVP would fall somewhere in between the utility-owned and customer-owned cases. If the third-party owner sells electricity to the utility, the price would likely be close to the utility's average production costs, so the project NPV would be similar to the utility-owned case.

Calculating fuel savings using average electricity production costs glosses over the fact that PV output occurs during the day, when production costs are typically higher than average. A more detailed analysis of how PV production correlates with marginal electricity costs over the day (and year) could be used to calculate the weighted average cost of electricity displaced by PV. If we assume that this weighted average is USD 60/MWh (rather than the USD 50/MWh annual average used above), the benefits increase by USD 169 million, giving the project an NPV of USD 211 million, a much more positive result.

Returning to the case of utility-owned PV (as originally presented), an array of variables could change the CBA result. For instance, raising the discount rate from 8% to 9% would give the project a negative NPV of USD 41 million. Likewise, lowering the social cost of carbon from USD 50/ton to USD40/ton gives the project a negative NVP of USD 80 million. In either of these cases, the project would not be viable based on quantitative benefits alone, though policymakers could still argue in favor of the project if qualitative benefits were valued highly enough.

DISCUSSION

Overall, the benefits of this project appear to slightly outweigh the costs. Policymakers would need to undertake a careful sensitivity analysis (beyond the simple examples given above) before deciding whether to move forward.

In addition, because the three largest benefits accrue to three different stakeholder groups (the utility, its customers and society at large), the project is only economically viable if a societal perspective is taken. Regulators may face a challenge in convincing all stakeholders to take this perspective. In addition, the costs of this project are front-loaded, while many of the benefits do not appear until years later. Therefore, financing the project may be challenging.

Annex II

Exercise 2:
Jamaica Case Study: Demand Response Programme With a Predefined Renewables Goal

JAMAICA CASE STUDY SUMMARY

This case study applies CBA to a hypothetical DR program in Jamaica. While Jamaica's primarily oil-fired electricity system has the flexibility needed to achieve its stated goal of 20% renewable electricity by 2030, this flexibility comes at the cost of reduced generator efficiency. And as a relatively small island, Jamaica does not benefit from the variability smoothing that typically comes with spreading wind and solar plants over a large geographic area. Nor is it able to export or import electricity from neighboring countries.

One goal of this DR program is to provide some load-side flexibility, reducing the impact of renewables on generation heat rates. Furhter goals are to reduce the involuntary shedding of customer loads and to defer the construction of addition peaking plants.

This case study is intended as an illustrative example of CBA, not an exhaustive engineering report; as such the CBA makes several simplifying assumptions, as detailed in the complete case study.

Electricity System Summary

- Jamaica Public Service (JPS) is the primary producer and sole distributer of electricity
- 540,000 customers
- 833 megawatt (MW) capacity, 90% oil-fired
- 644 MW peak demand
- Total system losses: 23% of generation
- Annual demand growth: 1.4%
- Electricity from renewable sources (wind, hydroelectric): 6%
- 2030 renewables goal: 20%
- Project Summary
- DR program targeted at large commercial and industrial (C&I) customers
- DR to be used for peak shaving and emergency response
- Project rollout: 2 years
- CBA time frame: 12 years
- DR participation rate: 60% of largest 4,000 customers
- DR capacity: 30 MW (5.25% of peak demand)
- Discount rate: 7%
- CBA perspective: societal (including JPS, its customers, and society at large)
- Baseline: achieve renewables goal without implementing DR

Benefits

The functions (as defined within this CBA methodology) of the DR program are to enable customer electricity-use optimization and real-time load management. These two functions map to the nine benefits summarized in Table AJ1. For more details on how each benefit's value was estimated, refer to the complete case study.

The project would also have the qualitative benefit of developing workforce skills that would be transferable to future DR projects.

Costs

Project costs are summarized in Table AJ2.

In addition to the costs in Table AJ2 incentive payments to participating customers are estimated to have an NPV of USD 14.9 million. However, these costs are transfer payments from one stakeholder to another and hence are not included in a CBA from society's perspective.

Discussion

The total present value of the project benefits is USD 30 million, while the total present value of the costs (excluding transfer payments) is USD 5 million. The benefits greatly exceed the costs, so the project is cost-effective.

One of the two primary benefits is the deferred construction of a new peaking plant for three years. If this benefit were not to materialize, the benefits would be reduced to USD 15 million, still well in excess of costs. The other primary benefit is fewer outages due to reduced load shedding. It is based on the assumption that 10% of DR megawatt-hours (MWh) will directly displace load shedding. If instead only 1% of DR displaces load shedding, this benefit is reduced from USD 13 million to USD 1.3 million. If both of these benefit reductions occur together, the benefits would be reduced to USD 3.3 million, and the project would not be cost-effective.

Overall, this project appears to be very financially beneficial from a societal perspective. Even from JPS's perspective, if the incentive payments to DR participants (NPV USD 15 million) are included as costs, the total costs of USD 20 million are still much less than the total benefits of USD 30 million.

Table AJ1: Values of benefits

Benefit	NPV (thousand USD)	Uncertainty level	Primary beneficiary
Optimized generator operation	1 300	Medium	JPS
Reduced generation capacity investments	15 000	Medium	JPS
Reduced ancillary service cost	0	Medium	JPS
Deferred distribution investments	0	High	JPS
Reduced electricity losses	450	Medium	JPS
Reduced electricity cost	0	High	Customers
Reduced sustained outages	13 000	High	Customers
Reduced CO_2 emissions	120	Medium	Society
Reduced SOx, NOx, and PM-10 emissions	70	Medium	Society

Table AJ2: Values of costs

Cost	NVP (thousand USD)	Estimation basis	Uncertainty level	Payer
Hardware	2 800	USD 75/kW DR capacity at start-up	Medium	JPS and customers
Administrative	740	USD 20/kW DR capacity at start-up	Medium	JPS
Operations	1 500	USD 5/kW DR capacity per year	Medium	JPS

Many island countries have high electricity prices, because they rely on imported fuels to produce electricity. Yet, islands have often abundant natural resources in the form of solar, wind, and ocean energy. This exercise is based on the conditions in Jamaica, which heavily relies on relies on fuel oil and diesel for electricity generation, but the suggested smart grid project is fictional.

Electricity in Jamaica is provided by a traditionally regulated, vertically integrated utility, Jamaica Public Service Company (JPS). Current (2012) installed electricity generating capacity in Jamaica is around 833 MW, of which 625 MW is owned by the utility and the remainder is owned by various nonutility organizations. On a generation basis, over 90% of electricity is produced from oil-burning power plants. Elevated oil prices make this a high-cost electricity system, with current residential retail electricity prices as high as USD 0.39/kWh. These relatively high rates constrain economic growth and competitiveness, and are a hardship for low-income residents. The Jamaican electricity system also suffers from considerable losses as over 20% of the electricity produced, does not earn revenue. Technical losses are 10%, while nontechnical losses (notably theft) are estimated at 12%.

Jamaica has considerable renewable energy potential, including biomass, solar, and wind. The country's 2009 National Energy Policy set a goal of 20% renewables by 2030. However, renewables supply less than 6% of Jamaica's electricity in 2012.

The combination of an aggressive renewables goal, high electricity prices and high electricity losses, makes Jamaica a promising setting for a smart grid project.

The prevalence of fast-ramping, oil-fired generation gives Jamaica's electric grid the flexibility to accommodate increased levels of renewables (Makhijani *et al.*, 2013). However, this flexibility comes at the cost of operating the generators away from their peak efficiency levels. In addition, as a small island with no connection to a larger grid, Jamaica cannot rely on electricity imports or exports to provide flexibility. Nor does it benefit significantly from the variability smoothing that typically comes with spreading wind and solar plants over a large geographic area (Makhijani *et al.*, 2013).

PROPOSED SMART GRID PROJECT DESCRIPTION

For this exercise, we assess the costs and benefits of an improved demand response (DR) programme for commercial and industrial electricity users (also referred to as a C&I DR programme) for Jamaica. The goals of this hypothetical program include decreasing the use of high-cost peaking plants, reducing load shedding and providing improved flexibility to aid integration of variable renewables.

Necessary Assumptions

This exercise is based on many simplifying assumptions. A real CBA should include more-detailed calculations and justifications of all assumptions. The primary assumptions made are described here. Additional benefit-specific and cost-specific assumptions are listed within Table J3 and Step 5, respectively.

As of 2011, JPS had installed 4,000 smart meters, which were targeted at its largest customers, accounting for 30% to 40% of energy sold (Makhijani, *et al.*, 2013). Some of these customers are on a time-of-use (TOU) pricing program (JPS, 2012). In addition, many of these customers have installed battery systems or other backup generation equipment to mitigate frequent outages. These backup systems could also be used to provide DR. Hence, much of the hardware necessary for a C&I DR programme is already in place. However, it is assumed that some additional communications and control hardware and software will be needed. In contrast to the already-established TOU pricing program, the DR program considered here will allow the utility to directly control some customer loads in exchange for payments to those customers.

It is worth noting that Jamaica's daily peak load is from 6:30 p.m. to 8:30 p.m. and is driven by residential demand. At first glance, then, it may seem preferable to implement a residential TOU pricing scheme rather than C&I DR. However, this would require installing smart meters and AMI across tens or hundreds of thousands of homes and would likely be a bigger leap from an implementation and logistics perspective.

While Jamaica is considering various changes to its electricity mix (aside from renewables), including adding natural gas or coal plants, we assume that the currently operating plants remain in use for the duration of this project. We also assume that JPS requires capacity to exceed peak demand by 130 MW to allow for plant maintenance and reserves. If significant changes are made to the generation mix, benefit estimates should be adjusted.

For customers in the DR program, the DR resource capacity is assumed to be equal to 25% of the customer's peak demand.

We assume an annual discount rate of 7%, an annual electricity demand growth of 1.4% (Jamaica Productivity Center, 2010), and an initial peak demand of 644 MW (Castalia, 2011). A 9.5% annual growth rate of RE production is assumed, allowing Jamaica to achieve its goal of 20% renewable electricity by 2030. Total system losses (including technical and nontechnical losses) are assumed to be 23% of generation.

APPLICATION OF METHODOLOGY:

STEP 1: DEFINE PROJECT

- Enroll 30% of C&I customers in DR programme per year over first two years of project, for a total enrollment of 60% of C&I customers.
- The DR resource will be used for peak shaving on a regular basis and for emergency response.
- Project term is 12 years.
- The CBA takes a societal perspective, with stakeholders being JPS, electricity consumers and society at large.

Because Jamaica has a preexisting renewables goal, this case study uses the Predefined Renewables Goal approach, meaning that the expanded renewables are considered part of the baseline. Some expansion of generation, transmission, and distribution to meet the growing load is also part of the baseline.

STEP 2: IDENTIFY FUNCTIONS

Table AJ3 shows a matrix mapping the DR resource to the smart grid functions it serves.

Table AJ3: Mapping Jamaica DR program to its functions

Functions	Technology: C&I DR
Fault current limiting	
Wide-area monitoring and visualization	
Dynamic capability rating	
Flow control	
Adaptive protection	
Automated feeder switching	
Automated voltage and VAR control	
Diagnosis and notification of equipment condition	
Enhanced fault protection	
Real-time load measurement and management	✓
Real-time load transfer	
Customer electricity-use optimization	✓

STEP 3: MAP FUNCTIONS TO BENEFITS

Table AJ4 shows how the two smart grid functions (see Table AJ3) identified in this case study, map to monetisable benefits.

Table AJ4: Mapping functions to benefits

Benefits	Function: Real-time load measurement and management	Function: Customer electricity-use optimisation
Optimized generator operation	✓	
Reduced generation capacity investments	✓	
Reduced ancillary service cost	✓	
Reduced congestion cost	✓	
Deferred transmission capacity investments	✓	
Deferred distribution investments	✓	
Reduced equipment failures		
Reduced distribution maintenance cost		
Reduced distribution operations cost		
Reduced meter reading cost		
Reduced electricity theft		
Reduced electricity losses	✓	
Reduced electricity cost		✓
Reduced sustained outages	✓	
Reduced major outages		
Reduced restoration cost		
Reduced momentary outages		
Reduced sags and swells		
Reduced fuel costs		
Reduced CO_2 emissions	✓	✓
Reduced SOx, NOx, and PM-10 emissions	✓	✓
Reduced wide-scale blackouts		

STEP 4: MONETIZE BENEFITS

This exercise assumes that Jamaica's renewable energy target is fixed, and that the benefits of the smart grid programme only need to consider the benefits to the electricity system. Table AJ5 shows estimated values, valuation methods, uncertainty levels and the primary beneficiaries of each of the benefits checked in Table AJ4. The largest benefits are reduced generation capacity investments and reduced sustained outages (meaning reduced load shedding in this case).

Table AJ5: Values of benefits

Benefit	Estimated value	Estimation basis	Uncertainty level	Primary beneficiary
Optimized generator operation	USD 225K/yr (year 12); NPV USD 1.3M	The DR program is predicted to provide 30 MW of capacity 2–4 pm daily, when the marginal electricity price is USD 0.22/kWh (Castalia, 2011). This demand is shifted to other times with an average marginal price of USD 21/kWh. This is assumed to occur on 80% of weekdays.	Medium	JPS
Reduced generation capacity investments	USD 7.9M/yr (years 6 through 8 only); NPV USD 15M	Around year 6 of the project, peak demand is expected to have risen enough to require an additional 120 MW diesel peaking plant. The 37 MW of DR can delay the construction of that plant for 3 years. The plant is assumed to cost USD 600/kW (Pauschert, 2009), or USD 84M. Assuming a 20-year asset life, the capital carrying charge is USD 7.9M/yr.	Medium	JPS
Reduced ancillary service cost	USD 0	It is likely that DR usage could reduce the need for frequency-related ancillary services by helping match load to generation, but no monetary value is assumed here.	Medium	JPS
Deferred distribution investments	USD 0	The DR program is assumed to reduce peak load on feeders that serve primarily C&I areas. However, the value of this benefit is very system-specific, so due to lack of feeder information, no monetary value is assumed here.	High	JPS
Reduced electricity losses	USD 76K/yr (year 12); NPV USD 450K	During peak times, T&D lines heat up, increasing resistance and losses. Shifting load away from peak times is assumed here to reduce line temperature by 5°C (Bockarjova and Andersson, 2007), thereby reducing line losses by 2% when DR is active.	Medium	JPS
Reduced electricity cost	USD 0	While the various utility cost reductions mentioned above should eventually result in some reduction in retail electricity prices, no assumption on the value of that benefit is made here. For the specific customers participating in the DR program, shifting load to off-peak times would bring no immediate cost reduction because time-based prices are not in place.	High	Customers
Reduced sustained outages	USD 2.2M/yr (year 12); NPV USD 13M	JPS currently sheds customer load frequently to maintain system stability. 10% of the MWh provided by the DR resource are assumed to displace load shedding. This avoided load shedding is assumed to have a value (VOLL) of USD 1/kWh.	High	Customers
Reduced CO_2 emissions	USD 19K/yr (year 12); NPV USD 120K	The loss reductions mentioned above lead to CO_2 reductions. We assume a social cost of carbon of USD 40/ton and each MWh from oil is assumed to produce 0.77 tons of CO_2.	Medium	Society
Reduced SOx, NOx, and PM-10 emissions	USD 11K/yr (year 12); NPV USD 70K	Loss reductions also lead to reductions in SOx, NOx, and PM-10 emissions. Each MWh produced from oil is assumed to produce 5 kg SOx, 3 kg NOx, and 1 kg PM-10. Reductions in SOx, NOx, and PM-10 are valued at USD 3.15, USD 0.70, and USD 0.20 per kg, respectively.	Medium	Society

Qualitative Benefits

This DR program would also have some nonmonetisable benefits, including the development of JPS's skills and procedures, which can be applied to future programmes. For instance, because Jamaica's peak load occurs in the evening due to residential demand, a good follow-on programme may be a residential TOU pricing or DR program aimed at reducing the system wide peak.

STEP 5: QUANTIFY COSTS

While some of the hardware needed for C&I DR is already installed, we assume that an additional USD 75/kW of DR capacity will be needed. We also assume administrative costs to enroll customers in the program and to set up communications and IT infrastructure will amount to USD 20/kW of capacity. Assumed incentive payments of USD 50/kW per year are transferred from the utility to the participating customers but have no net value, given the CBA's societal scope. Finally, we assume ongoing operational costs of USD 5/kW per year. These costs are summarized in Table AJ6.

The incentive payments of USD 14.9 million are not included in the costs, because the CBA methodology is applied from a societal perspective. This means that national transfers do not need to be considered. If this CBA methodology would have been applied from the perspective of JPS, these costs should have been considered in the CBA.

Table AJ6: Values of costs

Cost	Estimated NPV	Estimation basis	Uncertainty level	Payer
Hardware	USD 2.8M	USD 75/kW DR capacity at start-up; 37000 kW DR capacity in total.	Medium	JPS and customers
Initial administrative	USD 740K	USD 20/kW DR capacity at start-up; 37000 kW DR capacity in total.	Medium	JPS
Ongoing operations	USD 1.5M	USD 5/kW DR capacity per year;	Medium	JPS
300 000 kW DR capacity in total?	Medium	JPS	High	JPS
Incentive payments	USD 14.9M (transfer payment, not included in CBA)	USD 50/kW DR capacity per year paid from JPS to participating customers	Medium	JPS

STEP 6: COMPARE COSTS AND BENEFITS

The current total value of the project benefits is USD 30 million, while the current total value of the costs (excluding transfer payments) is USD 5 million. The benefits greatly exceed the costs, so the project is cost-effective. This is not surprising given that many real DR programs have been found cost-effective even from a utility perspective, which includes incentive payments as costs (Sandlin, 2009; U.S. DOE, 2006).

STEP 7: PERFORM SENSITIVITY ANALYSIS

Two benefits dominate the CBA. One is the deferred construction of a new peaking plant from year 6 (in the baseline case) to year 9. Many variables could affect this benefit, including load growth, plant capital costs, and other generation investments. In the most extreme case where no generation investment is deferred, this benefit would have zero value. In that case, the present value of benefits is reduced to USD 15 million, which still significantly, exceeds the costs.

The other large benefit is the reduction in outages due to load shedding. We assume 10% of DR MWh directly displaces shed-load MWh. If instead only 1% of DR MWh displaces load shedding, the present value of this benefit is reduced from USD 13 million to USD 1.3 million, and the total present value of benefits is reduced to USD 18 million, still well in excess of the costs. However, if both this benefit and the deferred construction benefit are reduced (to USD 1.3 million and USD 0, respectively), the total value of benefits falls to USD 3.3 million and the project no longer makes economic sense.

Like many smart grid projects, the costs of this project occur largely up front, whereas the benefits accrue over time. Hence, the CBA is fairly sensitive to discount rate: raising the rate from 7% to 10% reduces the present value of benefits by USD 5 million while leaving the costs largely unchanged.

DISCUSSION

Overall, from a societal perspective this project appears to be financially beneficial. Even from JPS's perspective, if the incentive payments to DR participants (NPV USD 15 million) are included as costs, the total costs of USD 20 million are still much less than the total benefits of USD 30 million.

There may, however, be a strong disincentive for JPS to implement DR as presently, JPS frequently sheds load to maintain system stability, and impacted customers are not compensated. Under a DR program, customers would have to be compensated when loads are reduced, so from the utility's perspective, it would be paying for something that it currently gets for free. In other words, from the customers' perspective, load shedding has a negative impact, but from the utility's perspective, the ability to shed loads has a positive impact.

This exercise demonstrates the importance of defining the scope of the CBA, and of considering all stakeholder perspectives. The insights could subsequently be used by regulators, like the Office of Utility Regulation of Jamaica, to develop regulation around load shedding to ensure that benefits are equally distributed among the different stakeholders in Jamaica.

Annex III

Methods of Benefit Valuation

Methods of Benefit Valuation

This section provides guidelines on how to monetize each benefit. Table ASG1 summarizes typical values and suggested valuation methods, and subsequent paragraphs provide additional details. Typical values in Table ASG1 are appropriate for developing countries unless otherwise indicated. Values given per ton are referenced to metric tons. Future values must be discounted to the present as described in Chapter 3.

Optimized Generator Operation

This benefit comes from two sources: avoided generator start-ups and improved efficiency (heat rate) due to operating each generator closer to its optimum output level (EPRI, 2010). The benefit (for each year) is the total annual cost of generation in the baseline case minus the total annual cost of generation with the proposed smart grid assets. If this benefit results from the use of energy storage, the efficiency of the storage system should be taken in to account when calculating the net benefit. To determine the value of this benefit rigorously, feed hourly (or subhourly) load and renewable output estimates into an electricity production cost model that captures the efficiency of the generators as a function of their output power level. Run the model both with and without the smart grid and renewable assets under consideration; the benefit for each year is the total annual cost to produce electricity in the baseline case minus the total annual cost to produce electricity with the smart grid project.

Rather than undertaking the detailed engineering study needed to model optimized generator optimization, it may be possible to estimate the benefits of optimized generation based on available studies of other electric systems. For instance, IEA (IEA, 2014a) introduces the concept of levelized cost of flexibility (LCOF) to estimate the cost of providing the grid flexibility needed to integrate variable renewables. IEA estimates that operating conventional generators more flexibly incurs costs ranging from below USD 1/MWh to above USD 20/MWh, depending on the type of generator and the amount of flexibility needed, with typical values around USD 4 to USD 10 per MWh. To the extent that DR, forecasting, or storage can improve generator operation, these flexibility costs associated with renewables can be avoided.

While production cost modeling is time-consuming, it may be able to help monetize several benefits simultaneously, especially this and the next four benefits listed. Note, however, that when using a production cost model to estimate benefits, it may not be possible to separate the contributions of individual benefit categories. However, such a methodology should give a better estimate of the total benefit than examining each benefit category individually. Production cost models vary in the level of detail they include; the model used should include enough detail to capture the expected benefits.

Reduced Generation Capacity Investments

The value of reduced generation capacity is monetized by estimating how much investment in a given generator type can be deferred and how long it can be deferred for. This can be determined by production cost modeling, or it can be estimated roughly based on the amount of load a smart grid asset is likely to remove or shift.

Often the generation assets whose purchase is deferred are peaking plants, especially when the technology in question is DR, storage, or PV. If the investment is expected to be deferred for the life of the project, then the value of the benefit is the cost per MW of peaking generation multiplied by the capacity of generation deferred in MW. For instance, 50 MW of DR (or combined DR and PV) reliably available during peak load hours, can defer up to 50 MW of peaking generation. IEA (2014b) provides typical cost ranges for various types of conventional generators per kW of capacity; for open-cycle gas turbines (typical peakers), the capital cost is between USD 400 and USD 900/kW.

Alternatively, if the investment is not deferred for the entire project period, the value of the benefit is the capital carrying charge per year for new generation multiplied by the number of years the purchase is deferred (EPRI, 2010).

Reduced Ancillary Service Cost

Ancillary services help make sure generation matches load at all times, regulating grid frequency. Voltage management–related grid services can also be considered ancillary services, though even deregulated systems rarely have voltage-related markets. Ancillary services are purchased on markets in some areas, but in many areas, especially in developing countries, they are simply provided by the grid operator as a necessary part of maintaining grid stability. Even in areas where markets establish explicit prices for some ancillary services, the benefit of reduced ancillary service cost may be "extremely hard" to estimate due to significant price variation (EPRI, 2010). Nevertheless, for some assets (for example, storage, DR, and some advanced wind inverters), it is possible to estimate the quantity of ancillary services expected (Ela *et al.*, 2013; Denholm *et al.*, 2013). It is also possible to estimate the value of those services (Kiviluoma and Gubina, 2013). Hence, the value of a small reduction in the need for ancillary services can be estimated by multiplying the quantity of services by the value per unit of those services. For example, if frequency regulation is valued at USD 10/MWh and a given asset is expected to provide 1 000 MWh of frequency regulation per year, the total benefit is USD 10 000 per year. However, this method only works if the amount of the ancillary service provided by the smart grid project is small compared to the total amount of that service used in the baseline case so that the price of the service is not affected by the increased supply (or reduced demand). If the amount of the ancillary service is large enough to affect the price of the service, a power system economic model may be needed to predict the value of this benefit.

The specific categories of ancillary services and their prices vary widely from region to region, so it is difficult to provide general guidance on prices. Compensation for ancillary services varies, often including a payment for capacity availability and a payment for energy provided. Generally, faster-responding services are valued more highly. The fastest-responding frequency-related service (called regulation in many areas) has average market prices around USD 20 to USD 60 per MWh, but they vary following daily and annual cycles in ranges from USD 10 to above USD 80 per MWh in North America (Monitoring Analytics, 2013). Voltage-related services are less common, but the value of bulk reactive power (which regulates voltage) appears to be on the same order of magnitude as frequency regulation, with average values ranging from USD 25 to USD 75 per mega-volt-ampere reactive (MVAR)-hour in one US region (Monitoring Analytics, 2013). Many other ancillary services exist; a comprehensive accounting of service categories and prices is beyond the scope of this report.

Reduced Congestion Cost

Congestion costs result when grid operators are unable to use the lowest-cost generation at a given time due to a shortage of transmission capacity to deliver the low-cost power to the load. Some detailed production cost models include transmission constraints and could be used to compare the total annual production cost of electricity both with and without smart grid or renewable assets that reduce congestion.

If you are not using a production cost model, it may be possible to obtain a rough estimate of the annual value of this benefit by estimating the number of hours per year that each transmission bottleneck is congested and multiplying that number by the estimated congestion cost. The congestion cost in this case is the difference between the cost of electricity from the dispatch plant and the cost of electricity from the plant that was not dispatched due to transmission congestion. Note that results of existing studies of congestion cost are not always comparable due to differing purposes and lack of information needed to evaluate the impacts of congestion relief (Lesieutre and Eto, 2003). That said, several U.S. independent system operators (ISOs) report annual congestion costs in the tens to hundreds of millions of dollars (Lesieutre and Eto, 2003).

Deferred Transmission Capacity Investments

The value of deferred transmission investment is monetized by estimating the amount of transmission capacity build-out that can be deferred and how long it can be deferred for. The annual benefit is equal to the capital carrying cost of the investment. The cost of transmission consists of line costs and the costs of the power stations at either end of the line. Typical line and station costs for alternating current (AC) and direct current (DC) transmission in Organization for Economic Cooperation and Development (OECD) member countries are given in IEA (IEA, 2014b). Line costs in developing countries may be lower because the cost of securing right-of-way is a significant component. Transmission line costs also depend on the terrain.

The most challenging part of estimating this benefit will be figuring out how much transmission capacity can be deferred. How to estimate this number depends on the specific technology enabling the deferral. Some basic guidelines are given in EPRI (EPRI, 2010). The amount of deferral depends on the ability of the smart grid technology to reduce line loading during peak transmission times.

Deferred Distribution Investment

Estimating the value of this benefit is similar to estimating the value of deferred transmission investment. Again, the annual value of the benefit is equal to the capital carrying charge of the deferred investment. Distribution system costs are very project-specific and consist of substations, medium-voltage cables, low-voltage transformers, and low-voltage cables. Typical component costs are given in (IEA, 2014b).

Again, the most difficult part of estimating this benefit is figuring out how much capacity can be deferred, which requires a distribution feeder-specific analysis. For an existing feeder, the best opportunities to defer investment come from reducing peak load on specific components that are nearly overloaded and will become overloaded as demand grows. For planned future feeders, the capacity of lines and transformers may be reduced if smart grid or renewable assets reduce peak loads.

Reduced Equipment Failures

Reduced equipment failures result from two sources: reduced exposure of equipment to fault currents and overloads, and monitoring and diagnosis of equipment condition (EPRI, 2010). In the first case, the benefit is equal to the cost of replacement multiplied by the portion of replacements caused by avoidable fault currents or overloads. In the second case, the benefit is equal to the cost of replacement multiplied by the portion of replacements that could be avoided through improved monitoring and diagnosis.

While the value of this benefit is hard to predict before implementing a project, it is seen as "one of the greatest benefits of smart grid technologies," often allowing equipment life to be extended by 1 to 10 years (EPRI, 2010).

Reduced Distribution Equipment Maintenance Cost

This benefit is realized when improved monitoring and diagnosis of equipment conditions leads to improved scheduling of maintenance. The annual value of this benefit is simply equal to the annual maintenance cost in the baseline case minus the annual maintenance cost with the smart grid project (EPRI, 2010). The value of this benefit is difficult to predict.

Reduced Distribution Operations Cost

This benefit is realized through automation and/or remote operation of feeder switches and capacitor banks. Its annual value is simply the annual cost to switch feeders and capacitors in the baseline case minus the annual cost to switch feeders and capacitors with the project in place (EPRI, 2010). The baseline cost can be estimated as the portion of a field crew's time spent switching feeders and capacitors multiplied by the annual cost of the field crew. The benefit can then be estimated by estimating the portion of switching tasks that can be eliminated through automation and remote operation.

Reduced Meter Reading Cost

Reduced meter reading costs largely result from a reduced need to send utility employees into the field to manually read meters. In the U.S., this has been estimated to cost USD 0.50 per meter per reading (HDR Engineering, 2007). The total annual benefit is equal to the cost per meter reading multiplied by the number of meter readings per year.

Reduced Electricity Theft

The greater granularity of metering associated with smart grids can help pinpoint and eliminate electricity theft. The annual value of this benefit is equal to the expected annual reduction in theft (in kWh) multiplied by the retail price of that electricity. Residential retail electricity prices range from USD 0.02 to USD 0.22 per kWh in developing countries (IEA, 2009). Industrial electricity prices in the developing world range from USD 0.01 to USD 0.22 per kWh (IEA, 2009).

It may be possible to estimate the amount of electricity theft on a system by subtracting metered load and estimated losses from metered generation. This benefit could be monetized by estimating the portion of the total theft that can be eliminated by the smart grid project.

Rates of electricity theft vary widely: In India it is estimated that one-third of all electricity is stolen, costing utilities USD 5 billion per year, while in China the theft rate is estimated at 8% (Silverstein, 2012).

Reduced Electricity Losses

The annual value of this benefit is equal to the expected annual loss reduction (in kWh) multiplied by the wholesale price of electricity, or by the production cost if no wholesale market exists. Wholesale electricity price data for the developing world are somewhat scarce since many countries lack wholesale markets, but it appears that they are in line with developed-country prices in most areas. Average developing-country wholesale/production power costs are typically in a range from USD 0.01 to USD 0.11 per kWh (IEA, 2014b; Rudnick, 2000; Gubbi, 2014).

If the reduced losses occur predominantly at a given time of day, the valuation of this benefit should use the corresponding time-based cost of electricity production.

Typical system losses in developing countries can be quite large; average losses in Latin America were 14.7% in 2005 (World Bank, 2012).

Reduced Electricity Cost

This benefit accrues to the customers. The annual value of the benefit is equal to the total annual difference in customers' electricity bills. Electricity bills often have an energy-based component and a peak-demand-based component. Retail energy rates are given in the subsection above, titled "Reduced Electricity Theft." Typical demand charges in the U.S. range from USD 5 to USD 20/kW per month.

The difficult part of estimating this benefit is estimating how much a given technology will reduce energy usage and/or peak demand. This is very project-specific, and even customer-specific. For DR programs, savings of up to 15% are typical (Cousineau, 2013).

Reduced Sustained Outages, Reduced Major Outages, and Reduced Momentary Outages

The benefits from various categories of outage reduction can be monetized using value of lost load (VOLL) metrics (EPRI, 2010; Giordano *et al.*, 2012a and 2012b). The benefits of reduced outages accrue to the customers whose reliability is improved. The VOLL per kWh varies depending on the type of customers served, the local level of economic activity, and other factors, with the highest values for industrial customers. In developed counties, VOLL ranges from EUR 1.5 to 13/kWh (Giordano *et al.*, 2012a and 2012b). The U.S. Department of Energy (DOE) provides a free online Interruption Cost Estimate Calculator that estimates VOLL for sustained interruptions. While this calculator is U.S.-specific, other countries could obtain rough estimates of local VOLL by scaling the calculator's output by the ratio of their per-capita gross domestic product (GDP) to the U.S. per-capita GDP. Country-specific per-capita GDP data are available from the World Bank. The DOE interruption cost estimator is based on (Sullivan *et al.*, 2009), which gives further information on how VOLL varies with time of year, duration of interruption, and customer type, noting these values on a per-kWh basis.

VOLL can also be measured on a per-outage basis rather than a per-kWh basis. If measured per outage, the VOLL will vary based on outage length.

A 2007 metastudy of VOLL studies reviewed methods of estimating VOLL and summarized numerical estimates of VOLL from both developed and developing countries, finding typical values of between USD 5 and USD 25/kWh and USD 2 and USD 5/kWh, respectively (van der Welle and van der Zwaan, 2007). This study also found that developing-country VOLL "almost certainly" falls between USD 1 and USD 10 per kWh.

The annual cumulative sustained outage time per customer can be estimated by multiplying two numbers that many utilities track: system average interruption duration index (SAIFI) and system average interruption frequency index (SAIDI) (EPRI, 2010). The cost of those outages per customer can then be found by multiplying this number by the VOLL per outage for that customer (for outages whose length is equal to SAIDI).

For momentary outages, it is more appropriate to use a VOLL metric measured per interruption rather than per kWh because the economic damage results primarily from the need to restart interrupted processes and is higher than the lost-kWh measurement would predict. Average costs associated with momentary outages in the U.S. are USD 6,600 per event for large C&I customers, USD 300 per event for small C&I customers, and USD 2 per event for residential customers (Sullivan *et al.*, 2009).

Reduced Restoration Cost

The benefit of reduced restoration costs comes largely from the reduced need to send technicians into the field to manually operate switches following an outage. If a switch can be controlled remotely, this "truck roll" can often be eliminated. In the U.S., the cost of a truck roll is roughly USD 275 (Gordon-Byrne, 2011). Note that if vehicle usage is reduced, there are likely benefits from reduced carbon dioxide (CO_2) and other pollutants that should be accounted for as well.

Reduced Sags and Swells

Voltage sags and swells often are not noticed by most customers. Reducing the number of these events is mostly of value to customers with sensitive loads (EPRI, 2010). A VOLL-like metric can be assigned to these voltage events based on the impact to customers. The value of this benefit is then the reduction in voltage events multiplied by the VOLL per event.

To estimate the value of reduced sags and swells, it helps to know how often these events occur. Systems without smart grid assets likely do not have this information, so the value of this benefit will have a high degree of uncertainty.

Reduced CO_2 Emissions

Reduced CO_2 emissions are a benefit of both wind and PV, as well as any smart grid technology that reduces fossil fuel consumption. The value of CO_2 reductions is not straightforward to quantify and is the subject of considerable debate. However, it is generally acknowledged that reduction of CO_2 has some economic value to society, and most analyses put the social cost of carbon (SCC) in the range of USD 40 to USD 140 per metric ton of CO_2 (UK DECC, 2013; Hope and Hope, 2013), though others argue it should be as high as USD 900 per ton (Ackerman and Stanton, 2012). Where carbon credit markets exist, prices are generally below USD 40 per ton, but these prices do not capture the full social cost (The Economist, 2013). Notably, electric utilities and energy companies that use carbon prices for internal planning use prices well above market values (The Economist, 2013). The economic benefits of reduced CO_2 emissions occur on a global level, so an immediate incentive to reduce emissions may not be felt by individual countries. Nevertheless, we recommend that some cost of carbon be included in a CBA. The amount of CO_2 produced by various conventional generators per kWh of electricity can be provided by numerous sources, such as the U.S. Energy Information Administration (EIA, 2014).

Reduced SOx, NOx, and PM-10 Emissions

Reductions in emissions of sulfur oxide (SOx), nitrogen oxide (NOx), and particulate matter (PM-10) pollutants should also be monetized based on the value to society of reduced impacts to human health and the environment. (EPRI, 2010) cites a National Research Council report (NRC, 2009) that gives ranges of monetary values per ton for each pollutant. The NRC report gives two sets of values: one for market values in emissions-permit-trading markets, and one for societal values. When doing a CBA with societal scope, the latter value should be used. The range of 50th-percentile values from the NRC report is shown in Table 4E for each pollutant type.

The quantities of SOx, NOx, and PM-10 emissions per kWh from various types of fossil-fueled power plants vary widely depending on the environmental controls installed on the plant. Typical sulfur dioxide (SO2) emission rates from coal power plants range from 0.26 to 18.5 grams per kWh, NOx rates from coal range from 0.49 to 4 grams per kWh, and PM-10 rates from coal range from 0.02 to 1.2 grams per kWh (von Blottnitz, 2006; Ito 2011). Contributions from oil-fired plants are in a similar range, while those from gas turbines are typically smaller; see Cai *et al*. (2012) for details by fuel and plant type.

Reduced Fuel Cost

When conventional generation is displaced by renewable generation, a primary benefit is the avoided fuel costs. While it may be possible to estimate exactly how much fuel of a given type is saved, it may be easier to calculate the number of megawatt-hours displaced. The benefit is then (MWh reduction in conventional generation) * (cost per MWh of conventional generation) * (portion of conventional generation cost driven by fuel costs). Typically fuel costs make up between 87% and 96% of generation costs (PJM, 2009), though the portion may be lower in less efficient markets. When using this method, it is best to analyze production costs based on time of day and time of year and estimate exactly when PV production occurs, as production costs vary significantly over time.

Reduced Wide-Scale Blackouts

The economic costs of large-scale blackouts can be very large, but estimating the value of improvements designed to reduce blackouts is difficult because it is hard to predict how often such events will occur.

For example, a large, two-day blackout in 2003 covering parts of the northeastern U.S. and southeastern Canada cost an estimated USD 4 billion to USD 10 billion (ELCON, 2004). Hard estimates of the cost of the 2012 multiple-hour blackout of a large section of India's grid are lacking, but the cost is estimated to be in the hundreds of millions of dollars (Silverstein, 2012).

Uncertainty in Benefit Values

There will inevitably be some degree of uncertainty in all benefit values. Estimate the magnitude of uncertainty of each benefit using the four-level scale given in EPRI (EPRI, 2010) as shown in Table 3E. Values with high uncertainty may be good candidates for sensitivity analysis. In addition, uncertainty estimates will allow decision-makers to gauge the overall level of certainty of the CBA.

Power System Modeling

When feasible, benefits should be quantified using appropriate computerized power system modeling methods. The type of model to be used depends on the type of benefit to be estimated. One such modeling method, mentioned above, is production cost modeling. Production cost modeling is a specific type of energy system modeling that focuses on minimizing the cost of electricity over a given time period for a given set of generation sources. IRENA has conducted a number of regional studies for the different African power pools (IRENA, 2015b). T&D system modeling can be useful as well. One challenge for such modeling is the need for input data of sufficient detail. Electric system operators can prepare for the needs of modeling by collecting load data at the highest spatial resolution available. T&D circuit details should also be recorded. When decision-makers do not have expertise in such modeling, engineering consultants can be hired. Power system models are discussed in many references, including (Welsch, 2013) and (Wood, 2012).

Table ASG1: Monetization of benefits

Benefit	Typical value (USD)	Valuation method(s)	Primary beneficiary
Optimized generator operation	Varies widely; 4–10/MWh if system has low-to-moderate renewable penetration	Hourly production cost modeling or rough estimation based on studies of other systems	Utility
Reduced generation capacity investments	Gas turbine 400–900/kW; CCGT 600–1 500/kW; coal 1 250–2 500/kW	Indefinite deferral: (MW reduction in peak load) * (cost/MW of peaking plant); deferral time < project life: (annual capital carrying cost) * (years investment is deferred)	Utility
Reduced ancillary service cost	Frequency regulation 20–60/MWh; frequency reserve 1–30/MWh; voltage 25–75/MVAR-hr (U.S.)	(Value of ancillary service per unit) * (units of ancillary service avoided)	Utility
Reduced congestion cost	Total congestion costs are 40M–1 200M per ISO) per year (U.S.)	Hourly production cost modeling or (hours of avoided congestion) * ((USD/MWh from dispatched plant) – (USD/MWh from constrained plant))	Utility
Deferred transmission capacity investments	AC 1 000M–1 500M/MW/km+ 50M–70M/line; DC 900M–1 200M/MW/km + 200M–350M/line (OECD)	(Annual capital carrying cost of deferred asset) * (years investment is deferred)	Utility
Deferred distribution investments	MV line 75k–100k/km; LV line 120k–140k/km; substation 1.3M–1.8M; LV transformer 5k–25k (OECD)	(Annual capital carrying cost of deferred asset) * (years investment is deferred)	Utility
Reduced equipment failures	Depends on type of equipment and method of failure reduction; extending equipment life by 1 to 10 years is typical	Failure due to overload/fault: (Total replacement cost) * (portion of failures due to overloads or fault currents); reduced failure due to diagnosis: (Total replacement cost) * (portion of failures reduced due to diagnosis)	Utility
Reduced distribution equipment maintenance cost	Project specific	(Baseline maintenance cost) – (project maintenance cost)	Utility
Reduced distribution operations cost	Project specific	(Baseline switching cost) – (project switching cost)	Utility
Reduced meter reading cost	0.50 per meter reading event (U.S.)	(Cost per meter reading event) * (reduction in meter reading events)	Utility
Reduced electricity theft	Household: 0.02–0.22/kWh; industrial: 0.01–0.22 /kWh	(Retail value per kWh of electricity) * (reduction in kWh stolen)	Utility
Reduced electricity losses	0.01–0.08/kWh; total losses 10–20% of generation	(Wholesale value per kWh of electricity lost) * (reduction in kWh lost)	Utility
Reduced electricity cost	Energy price per kWh for developing countries given above; demand charge: 5–20/kW (U.S.)	(Reduction in retail electricity price per kWh) * (kWh consumed) + (reduction in demand charge per kW) * (peak demand in kW)	Electricity users

Reduced sustained outages	2–5 per kWh lost	(VOLL per kWh) * (kWh reduction in outages); or SAIDI * SAIFI * (VOLL per outage of length SAIDI) * (# customers)	Electricity users
Reduced major outages	2–5 per kWh lost	(VOLL per kWh) * (kWh reduction in outages)	Electricity users
Reduced restoration cost	275 per truck roll (US)	(Cost of manual restoration event) * (reduction in restoration event)	Utility
Reduced momentary outages	Large C&I 6 600/outage; small C&I 300/outage; residential 2/outage (US)	(VOLL per outage) * (reduction in outages)	Electricity users
Reduced sags and swells	Customer specific	(VOLL per voltage event) * (reduction in events)	Electricity users
Reduced CO_2 emissions	40–140 per ton	(kWh displaced) * (tons CO_2 per kWh) * (SCC per ton CO_2)	Society
Reduced SOx, NOx, and PM10 emissions	6 300–6 600/ton SO_2; 1 400–1 900/ton NOx; 380–700/ton PM10 (US)	(tons of pollutant avoided) * (societal cost per ton of pollutant)	Society
Reduced fuel cost	Fuel costs typically make up 87% to 96% of production/wholesale cost per MWh	(MWh of conventional generation avoided) * (electricity production/wholesale cost per MWh) * (portion of production/wholesale cost attributed to fuel cost)	Utility
Reduced wide-scale blackouts	Varies widely	(economic cost of blackout) * (number of blackouts avoided)	Society

Annex IV

List of Smart Grid Technologies for Renewables

IRENA's publication 'Smart Grids and Renewables' provides an overview of six categories of six categories of smart grid technologies and applications that can be considered as "well-established" or "advanced." Energy storage and microgrids should also be considered as potential technology options, because they may find niche applications in emerging countries. This Annex provides a summary of these six categories of smart grid options.

Advanced metering infrastructure (AMI) *consists of smart electric meters and the communications and data-processing equipment needed to retrieve the meter data (King, 2005). Most studies report a net benefit to AMI projects (Sandlin, 2009; U.S. DOE, 2006), especially when automatic meter reading systems have not already been implemented (MetaVu, 2011). In countries where electricity theft is common, the reduction in theft associated with AMI alone may justify the investment (Cordero, 2010; Giordano et al., 2012a and 2012b) provides guidelines for CBA of AMI.*

Advanced electricity pricing *refers to a broad range of programs that try to make consumer electricity prices more closely reflect the real-time production costs of electricity, some of which also incorporate a location-based component. Advanced pricing schemes can be a powerful tool to reduce peak loads (Faruqui, 2010), which in turn reduces total electricity costs and can facilitate deferral of generation and transmission investments. In the context of RE, advanced pricing can be used to shape load profiles to better fit RE production patterns. Advanced pricing schemes could also offer end users a choice between various electricity products with different reliability requirements and different prices, providing affordable electricity for many while still offering highly reliable electricity to those who need it.*

Demand response (DR), *also called demand-side management (DSM), refers to techniques for reducing loads during peak times and/or when generation drops (either due to RE variability or a conventional generator going offline). Like advanced pricing (which some consider a subcategory of DSM), its benefits can include reduced peak loads, deferred generation and transmission investment, shaping of demand to better match renewable output, and increased reliability. A large-scale cost-benefit study of DR concluded that benefits outweigh costs by a factor ranging from 2 to 8, and that benefits increase as the share of RE increases. The study cautions that immature regulations, business models, and standards may delay full realization of these benefits (IEA, 2014a). The benefits of DR show strong synergy with PV (IRENA, 2013). (Woolf et al., 2013) provides a detailed framework for CBA of DR.*

Distribution automation (DA) *refers to various automated control techniques that optimize the operation of power distribution grids (IEEE, 2007/2008). DA is a core smart grid technology, is generally considered cost-effective, and is growing rapidly. The economic case for DA is best when replacing assets at the end of their lives, or when building new grids, as may be the case in developing countries. One key renewables-related application of DA is automated voltage regulation.*

Renewable resource forecasting *allows grid operators to plan for the inherent variability of wind and* *solar power. For systems with more than a few MW of wind capacity, the benefits are estimated to be in the tens to hundreds of millions of dollars per year (Milligan et al., 1995). Wind forecasting is generally accepted as advantageous and even necessary, but accurately predicting its value is system-specific and requires detailed data. See Chapter 7 of (Giebel et al., 2011) for a comprehensive review of studies that have examined the value of wind power forecasting in various power systems. Forecasting of PV is less mature and not widely used, but it's expected to mature as levels of PV on the grid rise (IRENA, 2013).*

Smart PV inverters and wind turbines with advanced grid support features *allow RE to interface with the grid in an optimal manner. They can ride through temporary abnormal grid conditions and help regulate grid voltage and frequency. Because they cost little more than conventional inverters, their benefits generally far outweigh their costs, and they are quickly becoming standard equipment.*

Energy storage *allows excess power on the electric grid to be stored for later. (See [IRENA, 2012] for an overview of energy storage.) Most grids contain very little energy storage, but as its costs fall, it may become a key factor in providing the flexibility needed to integrate renewables. In areas where geography permits, pumped hydro storage has long been economical, but other types of storage are now becoming economical. When electrifying isolated locations or islands, it may be more economical to create an isolated grid than to extend transmission infrastructure. In such cases, energy storage is often advantageous (IRENA, 2015c).*

Microgrids *are smaller electricity grids (for example, systems that provide village, neighborhood, or campus-scale service) that can operate independently of the bulk power system if needed. In the context of the developing world, the most relevant type of microgrid is the so-called remote microgrid, which is rarely or never tied to a larger grid. Remote microgrids can be used to provide power to villages or islands when distance or terrain makes a connection to the bulk grid uneconomical. Providing electricity to people who would otherwise not have access offers educational benefits, economic opportunities, and health benefits, among others. In contrast, grid-tied microgrids, which receive considerable research attention in some developed countries, are still a young technology requiring further development before widespread use and are not a focus of this report.*

Because the No Predefined Renewables Goal approach for CBA of smart grid projects (introduced in Chapter 2) also captures the costs and benefits of enabled renewables, we review the benefits of the two primary variable RE technologies: wind and solar PV.

Most smart grid assets will fall into one of the categories listed above, but CBA can also consider other smart grid or RE technologies as appropriate.

Wind power *has become quite widespread in many areas in recent years as its costs have fallen. In some areas, it has reached grid penetration levels that require engineering and operational efforts to integrate its variable output. Wind is typically installed in large farms of tens or hundreds of MW. In addition to reduction of fuel costs, benefits of wind power may include reduced capital investment in conventional generation and hedging against future fuel cost increases.*

Solar photovoltaics (PV) *have also seen large cost reductions in recent years. It is often installed in a distributed fashion, but multimegawatt centralized installations are becoming more common. The benefits of centralized PV plants are similar to the benefits of wind power. The benefits of distributed PV may also include reduced T&D losses and other factors (Hoke and Komor, 2012).*

Annex V

Smart Grids for Renewables: Real Case Studies

Bangladesh Prepay System

Off-grid household solar PV systems can provide electricity access in remote areas not served by the grid. Bangladesh has ambitious plans to install more such systems, but has been hampered by the costs and logistical challenges of "collections"—that is, payments from users to system installers and operators. By one estimate, less than half of all such payments are successfully completed and transferred.

A prepay system using mobile phones looks to be a promising solution to the collections challenge. Households purchase financial credit on their phones, and then send that credit to the PV system operator. An automated system then communicates that credit to the PV system and activates it. Many users have such phones, and are comfortable with using them as a payment vehicle. Electronic payments in advance reduce financial risks to system installers and operators, and avoid problematic cash handling. Advances in communication technologies make such payment systems possible.

Source: Moin, n.d.

Smart Microgrid in Chile

A remote community in Chile is using smart grid technologies to reduce diesel consumption by 50%. Huatacondo was receiving electricity from a diesel generator, which operated 10 hours per day. This generator-only system was replaced with a smart microgrid, which included a 23-kilowatt (kW) tracking PV system, a 3-kW wind turbine, a 140-kilowatt-hour (kWh) battery, and an energy management system (EMS). The EMS controls all the system components, providing dramatic reductions in diesel consumption, ensuring that batteries are charged appropriately, and maintaining water levels in the community water tank. It's the intelligence of the EMS that allows all the system components to work together and perform optimally.

Source: Hatziargyriou, 2014.

Smart Grids in Thailand

Thailand's Provincial Electricity Authority, which provides electricity outside main urban areas, is implementing a smart grid project in Pattaya, Chonburi. The first phase of this project includes 116,000 smart meters, using several communication technologies—mobile networks, power-line communication, and ZigBee. The second phase of the project will implement distributed renewables and other innovative technologies into the electricity system, including rooftop solar PV, electric vehicle charging, and distributed storage.

Source: Yuthagovit, n.d.

Annex VI

Glossary

Words and phrases are defined in a specific manner in the context of this document

Ancillary services – Power system services necessary to maintain a stable and reliable electricity system.

Baseline – A prediction of what would happen if the smart grid project were not implemented.

Benefit – Any impact of a project that may have value to any stakeholder. See Table 3C for a list of predefined smart grid benefits.

Benefit-to-cost ratio – The sum of the present value of a project's benefits divided by the sum of the present value of its costs.

Cash flow analysis – Looks at periodic (for example, annual) costs and benefits of a project over time.

Cost-benefit analysis – Rigorous financial analysis of the positive and negative impacts of a project.

Discount rate – The assumed annual rate used to find the present value of future costs and benefits.

Function – The roles that various smart grid technologies can play in improving grid operations.

Grid-friendly renewable controls – Controls that allow renewable energy sources to help stabilize the electric grid and provide ancillary services.

Monetize – Convert a quantifiable benefit into a monetary (for example, dollar) value.

Net present value – The sum of all project costs and benefits, with all future values discounted to the present using the discount rate, and all costs considered as negative values.

Qualitative benefit – A benefit that cannot be readily monetized.

REmap 2030 – A road map to double the share of renewable energy by 2030.

Ruritania – A hypothetical country used for illustrative purposes in this document.

Renewables – Energy resources that do not rely on an exhaustible resource.

Sensitivity analysis – A process used to evaluate the impact of a change in one or more variables on the outcome of a CBA.

Smart grid – A general category of technologies that apply communications information systems and controls to improve the operation of the electric power system.

Stakeholder – A group that is impacted by the project in question (for example, utility, customer, or society).

Definitions of smart grid functions

Fault current limiting – Fault current limiting can be achieved through sensors, communications, information processing, and actuators that allow the utility to use a higher degree of network coordination to reconfigure the system to prevent fault currents from exceeding damaging levels.

Wide-area monitoring and visualization – Wide-area monitoring and visualization requires time-synchronized sensors, communications, and information processing that allow the condition of the bulk power system to be observed and understood in real time so that action can be taken.

Dynamic capability rating – Dynamic capability rating can be achieved through real-time determination of an element's (e.g., line or transformer) ability to carry load based on electrical and environmental conditions.

Flow control – Flow control requires techniques that are applied at T&D levels to influence the path that power (real and reactive) travels. This uses such tools as flexible alternating current transmission systems (FACTSs), phase angle regulating (PAR) transformers, series capacitors, and very low impedance superconductors.

Adaptive protection – Adaptive protection uses adjustable protective relay settings (e.g., current, voltage, feeders, and equipment) in real time based on signals from local sensors or a central control system. This is particularly useful for feeder transfers and two-way power flow issues associated with high distributed energy resources penetration.

Automated feeder switching – Automated feeder switching is realized through automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. These devices can operate autonomously in response to local events or in response to signals from a central control system.

Automated voltage and VAR control – Automated voltage and VAR control requires coordinated operation of reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, and distributed generation (DG) with sensors, controls, and communications systems. These devices could operate autonomously in response to local events or in response to signals from a central control system.

Diagnosis and notification of equipment condition – Diagnosis and notification of equipment condition is defined as online monitoring and analysis of equipment, its performance, and its operating environment to detect abnormal conditions (e.g., high number of equipment operations, temperature, or vibration). The system automatically notifies asset managers and operators to respond to conditions that increase the probability of equipment failure.

Enhanced fault protection – Enhanced fault protection requires higher precision and greater discrimination of fault location and type with coordinated measurement among multiple devices. For distribution applications, these systems will detect and isolate faults without full-power reclosing, reducing the frequency of through-fault currents. Using high-resolution sensors and fault signatures, these systems can better detect high impedance faults. For transmission applications, these systems will employ high-speed communications between multiple elements (e.g., stations) to protect entire regions, rather than just single elements. They will also use the latest digital techniques to advance beyond conventional impedance relaying of transmission lines.

Real-time load measurement and management – This function provides real-time measurement of customer consumption and management of load through AMI systems and embedded appliance controllers. These systems help customers make informed energy-use decisions via real-time price signals, time-of-use (TOU) rates, and service options.

Real-time load transfer – Real-time load transfer is achieved through real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, increase distribution system efficiency, and enhance system performance.

Customer electricity-use optimization – Customer electricity-use optimization is possible if customers are provided with information to make educated decisions about their electricity use. Customers should be able to optimize toward multiple goals such as cost, reliability, convenience, and environmental impact.

Optimized generator operation – Better forecasting and monitoring of load and grid performance would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost.

Definitions of smart grid benefits

Reduced generation capacity investments – Utilities and grid operators ensure that generation capacity can serve the maximum amount of load that planning and operations forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Reducing peak demand and flattening the load curve should reduce the generation capacity required to service load, and lead to cheaper electricity for customers.

Reduced ancillary service cost – Ancillary services, including spinning reserve and frequency regulation, could be reduced if generators could more closely follow load. Ancillary services are necessary to ensure the reliable and efficient operation of the grid. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. The functions that provide this benefit reduce ancillary cost through improving the information available to grid operators.

Reduced congestion cost – Transmission congestion is a phenomenon that occurs in electric power markets. It happens when scheduled market transactions (generation and load) result in power flow over a transmission element that exceeds the available capacity for that element. Since grid operators must ensure that physical overloads do not occur, they will dispatch generation so as to prevent them. The functions that provide this benefit either provide lower-cost energy or allow the grid operator to manage the flow of electricity around constrained interfaces.

Deferred transmission capacity investments – Reducing the load and stress on transmission elements increases asset utilization and reduces the potential need for upgrades. Closer monitoring, rerouting power flow, and reducing fault current could enable utilities to defer upgrades on lines and transformers.

Deferred distribution investments – As with transmission lines, closer monitoring and load management on distribution feeders could potentially extend the time before upgrades or capacity additions are required.

Reduced equipment failures – Reducing mechanical stresses on equipment increases service life and reduces the probability of premature failure.

Reduced distribution equipment maintenance cost – The cost of sending technicians into the field to check equipment condition is high. Moreover, to ensure that they maintain equipment sufficiently, and identify failure precursors, some utilities may conduct equipment testing and maintenance more often than is necessary. Online diagnosis and reporting of equipment condition would reduce or eliminate the need to send people out to check equipment.

Reduced distribution operations cost – Automated or remote-controlled operation of capacitor banks and feeder switches eliminates the need to send a line worker or crew to the switch location in order to operate it. This reduces the cost associated with the field service worker(s) and service vehicle.

Reduced meter reading cost – Automated meter reading equipment eliminates the need to send someone to each location to read the meter manually.

Reduced electricity theft – Smart meters can typically detect tampering. Moreover, a meter data management system can analyze customer usage to identify patterns that could indicate diversion.

Reduced electricity losses – The functions that provide these benefits help manage peak feeder loads, locate electricity production closer to the load, and ensure that customer voltages remain within service tolerances, while minimizing the amount of reactive power provided. This improves the power factor and reduces line losses for a given load served.

Reduced electricity cost – The functions that provide these benefits could help alter customer usage patterns (DR with price signals or direct load control), or help reduce the cost of electricity during peak times through either production (DG) or storage.

Reduced sustained outages – Reduces the likelihood that there will be an outage, and allows the system to be reconfigured on the fly to help in restoring service to as many customers as possible. A sustained outage is one lasting more than five minutes, excluding major outages and wide-scale outages (defined below). The benefit to consumers is based on the value of lost load.

Reduced major outages – A major outage is defined using the beta method, per Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003 (IEEE, 2004). The functions listed can isolate portions of the system that include DG so that customers will be served by the DG until the utility can restore service to the area.

Reduced restoration cost – The functions that provide these benefits cause fewer outages, which result in fewer restoration costs. These costs can include line crew labor, material, and equipment; support services such as logistics; call centers; media relations; and other professional staff time and material associated with service restoration.

Reduced momentary outages – By locating faults or adding electricity storage, momentary outages could be reduced or eliminated. Moreover, fewer customers on the same or adjacent distribution feeders would experience the momentary interruptions associated with reclosing. Momentary outages last more than five minutes. The benefit to consumers is based on the value of service.

Reduced sags and swells – Locating high-impedance faults more quickly and precisely, and adding electricity storage, will reduce the frequency and severity of the voltage fluctuations that they can cause. Moreover, fewer customers on the same or adjacent distribution feeders would experience the voltage fluctuation caused by the fault.

Reduced CO_2 emissions – Functions that provide this benefit can improve performance in many aspects for end users. These improvements translate into a reduction in CO_2 emissions produced by fossil-based electricity generators.

Reduced SOx, NOx, and PM-10 emissions – Functions that provide these benefits can improve performance in many aspects for end users. These improvements translate into a reduction in SOx, NOx, and PM-10 emissions produced by fossil-based electricity generators.

Reduced fuel cost – The primary benefit of both wind and PV generation is the reduced cost of fossil fuels for conventional generators.

Reduced wide-scale blackouts – The functions that provide these benefits will give grid operators a better picture of the bulk power system, and allow them to better coordinate resources and operations between regions. This will reduce the probability of wide-scale regional blackouts.

Enabled-wind generation – Functions that provide these benefits can enable wind power by providing the needed operation flexibility, transmission capacity, and other services needed to increase wind energy usage.

Enabled solar generation – Functions that provide these benefits can enable solar power by providing the needed operation flexibility, transmission and distribution capacity, bidirectional power capability, and other services needed to increase PV energy usage.

Adapted from EPRI, 2010, Table 4-2

Annex VII

Bibliography

Ackerman, F., & Stanton, E. A. (2012). "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." Economics: The Open-Access, Open-Assessment E-Journal. doi:10.5018/economics-ejournal.ja. 2012-10.

Bockarjova, M., & G. Andersson (2007). "Transmission Line Conductor Temperature Impact on State Estimation Accuracy." Power Tech, 2007 IEEE Lausanne (pp. 701–706). Presented at the Power Tech, 2007 IEEE Lausanne.

Cai, H., M. Wang, A. Elgowainy, & J. Han (2012). "Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and Their Probability Distribution Functions for Electric Generating Units" (No. ANL/ESD/12-2). Argonne National Laboratory (ANL). Retrieved from *https://greet.es.anl.gov/files/updated-elec-emissions*.

The Economist. (2013, December 14). "Carbon Copy". Retrieved from *http://www.economist.com/news/business/21591601-some-firms-are-preparing-carbon-price-would-make-big-difference-carbon-copy*.

Castalia Strategic Advisors. (2011). "Options to Bring Down the Cost of Electricity in Jamaica" (Contract Report for JPS). Retrieved from *www.myjpsco.com/wp-content/uploads/jamaica_castalia_report.pdf?*

Cordero, M. A. (2010, February 26). "Puerto Rico Electric Power Authority—Company Overview and Project Development." Presented at the Puerto Rico Credit Conference 2010. Retrieved from *https://gdbapp.gdb-pur.com/prcreditconference/documents/2010PRCC-PREPA.pdf*.

Cousineau, D., K. Frank, & J. Fuisz. (2013, November 6). "Demand Response Programs Lower Electricity Costs, But Also Pose Risks." Manufacturing.net. Retrieved May 21, 2014, from *http://www.manufacturing.net/articles/2013/11/demand-response-programs-lower-electricity-costs-but-also-pose-risks*.

Denholm, P., J. Jorgenson, M. Hummon, T. Jenkin, D. Palchak, B. Kirby, O. Ma, & M. O'Malley. (2013). "The Value of Energy Storage for Grid Applications" (Technical Report No. NREL/TP-6A20-58465). NREL. Retrieved from *http://www.nrel.gov/docs/fy13osti/58465.pdf*.

Ela, E., V. Gevorgian, A. Tuohy, B. Kirby, M. Milligan, & M. O'Malley. (2013). "Market designs for the primary frequency response ancillary service—Part I: Motivation and design." Retrieved from *http://ieeexplore.ieee. org/xpls/abs_all.jsp?arnumber=6544662*.

(EPRI) Electric Power Research Institute. (2010). "Methodological Approaches for Estimating the Benefits and Costs of Smart Grid Demonstration Projects." (No. 1020342). Retrieved from *http://www.osti.gov/scitech/biblio/986425*.

(ELCON) Electricity Consumers Resource Council. (2004). "The Economic Impacts of the August 2003 Blackout."

Electricity Services Guide for Developers & Investors. (2012, June). "Jamaica Public Services Company." Retrieved from *http://www.myjpsco.com/wp-content/uploads/2013_Electricity_Services_Guide. pdf*.

EIA (Energy Information Administration). (2014). How much carbon dioxide is produced per kilowatt-hour when generating electricity with fossil fuels? FAQ. Retrieved May 21, 2014, from http://www.eia. gov/tools/faqs/faq.cfm?id=74&t=11.

Faruqui, A. (2010, March 9). "Dynamic Pricing & Customer Behavior." Presented at the Fourth Annual Electricity Conference.

Giebel, G., R. Brownsword, G. Kariniotakis, M. Denhard, & C. Draxl. (2011). "The State-of-the-Art in Short-Term Prediction of Wind Power." ANEMOS.plus.

Giordano, V., I. Onyeji, G. Fulli, M. S. Jimenez, & C. Filiou. (2012a). "Guidelines for Conducting Cost-Benefit Analysis of Smart Grid Projects" (JRC Reference Reports, European Commission). Joint Research Centre. Retrieved from http://ec.europa.eu/energy/gas_electricity/smartgrids/doc/20120427_smartgrids_guideline.pdf.

Giordano, V., I. Onyeji, G. Fulli, M. S. Jimenez, & C. Filiou. (2012b). "Guidelines for Conducting Cost-Benefit Analysis of Smart Metering Deployment" (JRC Reference Reports, European Commission\). Joint Research Centre. Retrieved from ses.jrc.ec.europa.eu/sites/ses/files/documents/guidelines_for_cost_benefit_analysis_of_smart_metering_deployment.pdf.

Gordon-Byrne, G. (2011, August 25). "Three Big Band-Aids." Intelligent Utility. Retrieved April 18, 2014, from http://www.intelligentutility.com/article/11/08/three-big-band-aids.

Gubbi, S. (2014, September 10). "Cost of generating power in India." The Alternative. Retrieved from http://thealternative.in/environment/cost-of-generating-power-india/.

Hatziagyriou, N. (2014). Microgrids, Architectures and Control. Wiley and Sons, IEEE press. 2014.

HDR Engineering. (2007). "Water Meter Plan and System Evaluation. City of Dubuque, Iowa." Retrieved from http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=7&ved=0CF4QFjAG&url=http%3A%2F%2Fwww.cityofdubuque.org%2FDocumentView.aspx%3FDID%3D1946&ei=E11RU7XGE5WryAS284CIBw&usg=AFQjCNH1tcYnx2wFo-CORk6znKCKOQFyWw&sig2=R1691TYH8mbYUr5ibdn-cA&bvm=bv.65058239,d.aWw.

Hoke, A., R. Butler, J. Hambrick, & B. Kroposki. (2013). "Steady-State Analysis of Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders." IEEE Transactions on Sustainable Energy. Retrieved from http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=6357275.

Hoke, A., & P. Komor. (2012). "Maximizing the benefits of distributed photovoltaics." The Electricity Journal, 25, 55–67.

Hope, C., & M. Hope. (2013). "The social cost of CO2 in a low-growth world." Nature Climate Change, 3, 722–724.

IEEE/PES Distribution Automation Tutorial 2007/2008. (2007, 2008). "Power Distribution Research: Smart Distribution Wiki." Retrieved May 20, 2014, from http://wiki.powerdistributionresearch.com/index.php?title=IEEE/PES_Distribution_Automation_Tutorial_2007/2008.

IEA (International Energy Agency). (2009). "Energy Prices & Taxes—Quarterly Statistics, Fourth Quarter 2009."

IEA. (2014a). The Power of Transformation—Wind, Sun and the Economics of Flexible Power Systems. Available at www.iea.org.

IEA. (2014b). The Impact of Global Coal Supply on Worldwide Electricity Prices. Available at www.iea.org.

Interruption Cost Estimate (ICE) Calculator - BETA. (n.d.). Retrieved May 21, 2014, from http://www.icecalculator.com/ice/.

IRENA (International Renewable Energy Agency). (2012). "Electricity Storage and Renewables for Island Power: A Guide for Decision Makers." Retrieved from www.irena.org.

IRENA (2013). "Smart Grids and Renewables: A Guide for Effective Deployment." IRENA. Abu Dhabi. Retrieved from http://www.irena.org/DocumentDownloads/Publications/smart_grids.pdf.

IRENA (2015a). Renewable Power Generation Costs in 2014. IRENA. Abu Dhabi. January 2015. ww.irena.org/costing.

IRENA. (2015b). Africa Power Sector: Planning and Prospects for Renewable Energy. IRENA. Abu Dhabi. www.irena.org/publications.

IRENA. (2015). Renewables and electricity storage. A Technology roadmap for REmap 2030. IRENA. Abu Dhabi. June 2015. www.irena.org/publications.

Ito, O. (2011, November 29). "Emissions from coal fired power generation." Presented at the Workshop on IEA High Efficiency, Low Emissions Coal Technology Roadmap, New Delhi. Retrieved from https://www. iea.org/media/workshops/2011/cea/Ito.pdf.

Jamaica Productivity Centre. (2010). "Generation and Distribution of Electricity in Jamaica: A regional comparison of performance indicators." Retrieved from http://www.jpc.com.jm/docs/Generation%20 and%20 Distribution%20of%20Electricity%20in%20 Jamaica.pdf.

Kiviluoma, Juha & Andrej Gubina. (2013). "D2.3: Ancillary services costs for different services and different conventional generators." REserviceS. Retrieved from http://www.reservices-project.eu/publications-results/d2-3_reservices_as-costs/.

King, C. (2005). "Advanced Metering Infrastructure (AMI)." Retrieved from www.oregon.gov/PUC/electric_gas/010605/king.pdf?ga=t.

Kirby, B. J. (2005). "Frequency regulation basics and trends." United States Department of Energy. Retrieved from http://www.ferc.gov/C ale nda rFile s/201 0 052608 593 7- K irby,%20 Frequency%20 Regulation%20Basics%20and%20 Trends.pdf.

Lesieutre, B. C., & J. H. Eto. (2003). "Electricity Transmission Congestion Costs: A Review of Recent Reports." (No. LBNL-54049). Lawrence Berkeley National Laboratory. Retrieved from http://energy. gov/oe/downloads/electricity-transmission-congestion-costs-review-recent-reports.

Makhijani, S., A. Ochs, M. Weber, M. Konold, M. Lucky, & A. Ahmed. (2013). "Jamaica Sustainable Energy Roadmap: Pathways to an Affordable, Reliable, Low-Emission Electricity System." Worldwatch Institute. Retrieved from http://www.worldwatch.org/system/files/Jamaica-Sustainable-Energy-Roadmap-112013.pdf.

MetaVu. (2011). "SmartGridCityTM Demonstration Project Evaluation Summary." Retrieved from https://www.smartgrid.gov/sites/default/files/doc/files/SmartGridCity_Demonstration_Project_Evaluation_Summary_201109.pdf.

Milligan, M. R., A. H. Miller, & F. Chapman. (1995). "Estimating the economic value of wind forecasting to utilities." National Renewable Energy Laboratory Golden, Colo. Retrieved from http://www.nrel.gov/docs/legosti/old/7803.pdf.

Munawar Misbah (n.d.). Prepayment for Sustainable SHS Growth, Rahimafrooz Solar.

Monitoring Analytics, LLC. (2013). "Quarterly State of the Market Report for PJM: January through March." Retrieved from http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2013/2013q1-som-pjm-sec9.pdf.

NEMA (National Electrical Manufacturers' Assocation). (2013). "Volt/VAR Optimization Improves Grid Efficiency".

NRC (National Research Council). (2009). "Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use." Retrieved from http://www.google.com/url ?sa=t&rct=j&q=&esrc=s&source=web&cd=2&ved=0C DgQFjAB&url=http%3A%2F%2Fmedia.kentucky.com%2Fsmedia%2F2009%2F10%2F19%2F10%2FHiddenC osts.source.prod_affiliate.79.pdf&ei=AI1RU5raIYaGyA Td54CYBA&usg=AFQjCNFUkNYw0dv5ZiSMmojGV2u 2WqLzsw&sig2=pvxmUD-uvjcd0O2Z2i68tw&bvm=bv .65058239,d.aWw.

"Neural Energy: Distribution Automation," (2011). http://www.neuralenergy.info/2009/06/distribution-automation.html.

Pauschert, D. (2009). "Study of Equipment Prices in the Power Sector (Technical Paper No. 122/09)." Energy Sector Management Assistance Program. Retrieved from http://www.esmap.org/sites/esmap. org/files/TR122-09_GBL_Study_of_Equipment_ Prices_in_the_Power_Sector.pdf.

Perez, R., & T. Hoff. (2008). "Energy and Capacity Valuation of Photovoltaic Power Generation in New York." Clean Power Research. Retrieved from http://asrc.albany.edu/people/faculty/perez/publications/Utility%20Peak%20Shaving%20and%20Capacity%20C re dit / Pa p e r s % 20 o n% 20 PV% 20 Lo a d% 20 Matching%20and%20Economic%20Evaluation/Energy%20Capacity%20Valuation-08.pdf.

PJM (2009). A Review of Generation Compensation and Cost Elements in the PJM Markets. http://www.pjm.com/~/media/committees-groups/committees/

mrc/20100120/20100120-item-02-review-of-generation-costs-and-compensation.ashx.

Rudnick, H. (2000, April 25). "Electricity Markets in Latin America: Costs, Prices and Quality of Service." London. Retrieved from http://web.ing.puc.cl/~power/paperspdf/RudnickIEE.pdf.

Sandlin, D. (2009, September 15). "Rate Design to Complement AMI Implementation in Danville, Virginia." Presented at the APPA 2009 Business & Finance Conference. Retrieved from http://www.publicpower.org/files/PowerPoint/Sandlin,%20Denise%20-%20Rate%20Design%20to%20Complement%20AMI%20Implementation%20in%20Danville,%20VA.ppt.

Silverstein, K. (2012, August 1). "India's Blackout Is Enlightening." EnergyBiz. Retrieved April 21, 2014, from http://www.energybiz.com/article/12/08/india-s-blackout-enlightening.

Sullivan, M. J., M. Mercurio, & J. Schellenberg. (2009). "Estimated Value of Service Reliability for Electric Utility Customers in the United States" (No. LBNL-2132E). Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, Calif. Retrieved from http://www.osti.gov/energycitations/product.biblio. jsp?query_id=0&page=0&osti_id=963320.

UK Department of Energy and Climate Change (2013) "Updated Short-Term Values Used for UK Public Policy Appraisal: 2013 - Publications." Accessed March 26, 2014. https://www.gov.uk/government/publications/traded-carbon-updated-short-term-values-used-for-uk-public-policy-appraisal.

Uluski, Robert (2013). "Developing a Business Case for Distribution Automation." Electric Light and Power, June 6, 2013.

U.S. DOE (Department of Energy). (2006). "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them." Retrieved from http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/DOE_Benefits_of_Demand_Response_in_Electricity_Markets_and_Recommendations_for_Achieving_Them_Report_to_Congress.pdf.

Van der Welle, A., & B. van der Zwaan. (2007). "An Overview of Selected Studies on the Value of Lost Load (VOLL) (Working Paper)." Amsterdam: Energy Research Centre of the Netherlands (ECN).

Von Blottnitz, H. (2006). "A comparison of air emissions of thermal power plants in South Africa and 15 European countries." Journal of Energy in Southern Africa, 17, 72–81.

Welsch, M. (2013). Enhancing the Treatment of Systems Integration in Long-term Energy Models, PhD Thesis, 2013.

Wood, A. J., And Wollenberg, B. F. (2012). Power generation, operation, and control, Wiley and Sons.

Woolf, T., E. Malone, L. Schwartz, & J. Shenot. (2013). "A Framework for Evaluating the Cost-Effectiveness of Demand Response. National Action Plan for Demand Response." Retrieved from http://emp.lbl.gov/sites/all/files/napdr-cost-effectiveness.pdf.

World Bank. (2012). "Benchmarking Analysis of the Electricity Distribution Sector in the Latin American and Caribbean Region."

Yuthagovit, P. Status Quo and Investment Planning in Smart Grid in Thailand. Provincial Electricity Authority. Not dated. www.pea.co.th.

IRENA
International Renewable Energy Agency

www.irena.org