# Long-Term Renewable Energy Planning Model for Remote Communities

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***Abstract*—The paper presents a novel long-term Renewable Energy (RE) planning model for Remote Communities (RCs), considering the characteristics of diesel-based RCs in Canada and other parts of the world such as Alaska and northern Chile. Over the past few years, there has been a significant increase in assessing and deploying RE projects in northern remote locations. The model proposed in this paper adds to such efforts by creating a multiple-year community planning tool that can be used to determine economic and technically-feasible RE solutions, considering the current operating structures, electricity pricing systems, subsidy frameworks, and project funding alternatives under which RE can be deployed in RCs. The proposed model is implemented in a case study for the Kasabonika Lake First Nation community in northern Ontario. The case study shows that RE projects can be feasible under current operating conditions, for a set of funding alternatives that share the economic risks.**

***Index Terms*—Microgrids, remote community, renewable generation, power generation planning, microgrid economics, diesel generators.**

## NOMENCLATURE

*System parameters*

| | |
|---|---|
| $BLT_k$ | Loan term [years]. |
| $CD_i$ | Selling or savings electricity applicable rate for customer $i$ [$/kWh]. |
| $CPI$ | Customer Price Index. |
| $CT_i$ | Binary value used for distinguishing between RE curtailment classes. |
| $C_{FUEL}$ | Actual oil-based fuel price [$/litre]. |
| $ELT_k$ | Operation lifetime for equipment $k$ [years]. |
| $INC_i$ | External incentive rate for customer $i$ [$/kWh]. |
| $IRR_i^{\mathbf{max}}$ | Maximum Internal Rate of Return (IRR) required for a feasible deployment plan [%]. |
| $IRR_i^{\mathbf{min}}$ | Minimum IRR required for a feasible deployment plan for customer $i$ [%]. |
| $P_{D_{i,t,h}}$ | Customer $i$ load on year $t$ at hour $h$ [kW]. |
| $P_{D_{t,h}}$ | Community demand on year $t$ at hour $h$ [kW]. |
| $P_{FG_{BASE_{j,t,h}}}$ | Required active power for baseline scenario produced by Fuel-based Generator (FG) $j$ on year $t$ at hour $h$ [kW]. |
| $P_{REm_{k,g,t,h}}$ | Active power output obtained for each equipment unit $k$ combined with complementary unit $g$ from the respective RE model on year $t$ at hour $h$ [kW]. |
| $P_{REm_{k,t,h}}$ | Active power output obtained for each equipment unit $k$ from the respective RE model on year $t$ at hour $h$ [kW]. |
| $RC_{CAP_k}$ | Present capital cost for Renewable Energy (RE) equipment $k$ per installed capacity unit [$/kW]. |
| $RC_{OM_k}$ | Present Operation and Maintenance (O&M) cost RE equipment $k$ per installed capacity unit [$/kW]. |
| $RD_i$ | Discount rate for customer $i$ [%]. |
| $RP_t^{\mathbf{min}}$ | Rated power for the smallest nominal power FG operating on year $t$ [kW]. |
| $RP_k$ | Nominal rated power for equipment $k$ [kW]. |
| $b_{CB}^{\mathbf{max}}$ | Maximum Capacity Building (CB) reduction percentage [%]. |
| $b_{IC_t}^{\mathbf{max}}$ | Maximum allowable RE installed capacity ratio with respect to the average annual load on year $t$. |
| $b_{CBb}$ | Constant coefficient for CB linear equation. |
| $b_{CBm}$ | Linear coefficient for CB linear equation. |
| $b_{CBu}$ | Number of RE units to be installed to achieve maximum CB cost reduction. |
| $b_{CEP}$ | In-hand capital contribution ratio available at the start of the project. |
| $b_{CFP_t}$ | Percentage of the total fuel consumption supplied by the community to the utility on year $t$ [%]. |
| $b_{D_i}$ | Customer $i$ load ratio of the total community demand. |
| $b_{EFP}$ | Project external funding ratio of the total project capital cost. |
| $b_{OM_t}$ | Annual O&M variation due to technology change on year $t$. |
| $d_{GS}^{\mathbf{min}}$ | Minimum operation load ratio for FGs. |
| $d_{GSLIM_{i,t}}$ | FG operation limit at which RE is curtailed when reached [kW]. |
| $d_{GSa_j}$ | Linear fuel consumption coefficient for diesel generator $j$ [litre/kW]. |
| $d_{GSb_j}$ | Constant fuel consumption coefficient for diesel generator $j$ [litre]. |
| $f_{BASE_t}$ | Fuel consumption baseline obtained from currently installed generation equipment on year $t$ [litre/year]. |
| $r_B$ | Loan interest rate [%]. |
| $r_i$ | Inflation rate for the applicable electricity tariff for customer $i$ [%]. |
| $r_{FR}$ | Percentage revenue obtained by the community from fuel sales for electricity generation [%]. |

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*Solar parameters*

$C_{PVINV_g}$ Capital cost for solar inverter type $g$ [$/unit].
$C_{PVOM_k}$ O&M cost for Photovoltaic (PV) equipment type $k$ [$/unit].
$C_{PVU_k}$ Capital cost per PV solar panel for equipment type $k$ [$/unit].

*Wind parameters*

$C_{WTOM_k}$ O&M cost for Wind Turbine (WT) type $k$ [$/unit].
$C_{WTTWR_{k,g}}$ Capital cost for tower type $g$ for WT type $k$ [$/unit].
$C_{WTU_k}$ Capital cost per WT for equipment type $k$ [$/unit].

*Variables*

$CB_{k,t}$ Cost reduction ratio due to capacity building for equipment type $k$ on year $t$.
$C_{BL_{i,k,t}}$ Loan obtained for purchasing equipment type $k$ for customer $i$ on year $t$ [$].
$C_{BPMT_{i,k,t}}$ Amortization loan payments for equipment type $k$ for customer $i$ on year $t$ [$].
$C_{CAP_{i,k,t}}$ Capital cost of equipment $k$ for customer $i$ installed on year $t$ [$/kW].
$C_{CE_{i,k,t}}$ Initial capital expense contribution for equipment type $k$ for customer $i$ on year $t$ [$].
$C_{EF_{i,k,t}}$ External funding available for equipment type $k$ for customer $i$ on year $t$ [$].
$C_{OM_{i,k,t}}$ O&M cost of on-site equipment $k$ for customer $i$ on year $t$ [$/kW].
$C_{TEQ_{k,g}}$ Total Net Present Value (NPV) for equipment type $k$ using complementary unit type $g$ [$].
$C_{i,t}$ Total capital and O&M of RE equipment for customer $i$ on year $t$ [$/year].
$EOS_{i,k,t}$ Number of RE equipment units on-site for equipment $k$ for customer $i$ on year $t$.
$EQC_{k,t}$ Cumulative number of on-site equipment type $k$ by year $t$.
$IRR_i$ IRR for RE operation for customer $i$ [%].
$IS_{i,t}$ Income or saving obtained from RE for customer $i$ on year $t$ [$/year].
$LC_{k,g}$ Levelized Cost of Energy (LCOE) for equipment type $k$ using complementary unit type $g$ [$/kWh].
$LR_{i,t}$ Community loss opportunity cost from diesel sell due to RE generation for customer $i$ on year $t$ [$/year].
$P_{DB_{i,t,h}}$ Active power difference between the available RE for customer $i$ and the respective load on year $t$ and hour $h$ [kW].
$P_{FG_{proj_{j,t,h}}}$ Required active power for RE projects scenarios by FG $j$ on year $t$ at hour $h$ [kW].
$P_{FG_{t,h}}$ Required active power output from FG plant on year $t$ at hour $h$ [kW].
$P_{REa_{i,k,t,h}}$ Renewable active power available for customer $i$ for equipment $k$ on year $t$ at hour $h$ [kW].
$P_{REc_{i,k,t,h}}$ Renewable active power curtailed for customer $i$ for equipment $k$ on year $t$ at hour $h$ [kW].
$P_{REu_{i,k,t,h}}$ Renewable active power used to supply the load for customer $i$ and equipment $k$ on year $t$ at hour $h$ [kW].
$W_{i,t}$ Social welfare for customer $i$ on year $t$ [$/year].
$f_{PROJ_t}$ Fuel consumption obtained when considering RE projects on year $t$ [litre/year].
$x_{PVP_{k,g}}$ Integer variable for the number of solar PV panels connected in parallel for equipment type $k$ when connected to inverter type $g$.
$x_{PVS_{k,g}}$ Integer variable for the number of solar PV panels connected in series for equipment type $k$ when connected to inverter type $g$.
$x_{i,k,t}$ Integer variable for the number of RE units to be deployed for equipment type $k$ for customer $i$ on year $t$.
$y_{i,k,u,s}$ Auxiliary variable to represent on-site equipment $k$ during its operation lifetime.
$z_{i,t,h}$ Renewable active power used ratio for customer $i$ on year $t$ at hour $h$.

*Indices*

$g$ Complementary equipment to be used with unit $k$; $g = 1, ..., G$.
$h$ Hours in a year; $h = 1, ..., H$.
$i$ Subsidized unsubsidized or avoided fuel cost customer type; $i = 1, ..., I$.
$j$ FG unit to be considered; $j = 1, ..., J$.
$k$ Solar or wind technology equipment to be considered; $k = 1, ..., K$.
$t$ Year; $t = 1, ..., T$.

## I. Introduction

HIGH energy costs, together with technical, environmental, and social aspects, have gradually triggered Renewable Energy (RE) assessments, projects, and policies in Remote Communities (RCs). In particular, previous and ongoing projects have been paving the way for further RE development in Canada's northern locations from the Yukon to Newfoundland, (e.g., [1]–[3]), with recent efforts to increase the access to energy-related information from RCs in order to promote further developments [4], [5]; also, there has been escalating efforts to assess appropriate equipment, natural resources, and economic feasibility of such projects (e.g., [6], [7]). While pointing out the potential of RE projects, these efforts highlight the shortcomings as well as the technical and economic barriers that are yet to be overcome [5], [8], which include electric energy storage systems that, for medium or high RE penetration levels, are yet to significantly decrease the overall cost of energy under current deployment conditions [9], [10]. Furthermore, to properly evaluate the technical and economic RE aspects of such projects, from a planning perspective, there are still limited tools that consider the specific challenges of RCs; this is the focus of this paper.

There has been significant work regarding RE microgrid planning and sizing considering different model detail levels,

objective function(s), and equipment characteristics [11]. Detailed dynamic models have been proposed to assess feasibility of RE configurations based on energy availability and equipment downtime [12], thus resulting in technically-feasible solutions, but not necessarily economically viable. Further deterministic models have been used for economic evaluations considering trade-offs between reliability and cost [13], as well as proposing multi-objective Interval Linear Programming (ILP) to assess risk levels for different configurations [14]. These previous approaches consider significant levels of detail while accounting in some cases for some of the uncertainties that result from microgrid sizing; however, the long-term role of the associated community and funding details have not been considered. On the latter, investment opportunities have been analyzed for grid-connected microgrid models dealing with investment periods and uncertainties [15]; some of these concepts can be translated to RCs, as shown in this paper.

Microgrid sizing software considering different approaches are available. Thus, HOMER is a widely-used software for microgrid sizing that determines the minimum Net Present Value (NPV) configuration [16]; however, the software considers individual projects with the same operating structure, which can be a limiting factor when creating a RE plan for a community. Also, DER-CAM is a comprehensive economic and environmental model that can be used for determining the minimum cost equipment configuration for a microgrid [17]; however, multiple-year investment and project funding alternatives are not considered. These shortcomings are addressed in the present paper.

Previous projects, assessments, planning models, and software tools have helped understand the complexity and requirements of deploying RE in RC microgrids. Nevertheless, currently, there is a gap from the planning perspective to help communities understand and quantify the potential of RE and the benefits that RE projects can bring, given the current operating and framework constraints. Hence, the objective of the present paper is to use existing equipment and economic models to propose a comprehensive RE long-term planning model that accounts for all relevant and current technical, economical, and operating conditions of RCs. The proposed model considers the characteristics of some of the previously deployed RE northern projects and previously described planning models which apply directly to RCs. In addition, the model acknowledges some of the significant roles that the community plays regarding potential RE project deployments, as well as quantifying the project benefits.

The rest of the paper is organized as follows: Section II discusses the different electricity rates and subsidy framework in Northern and Remote Communities (N&RCs) in Canada, and their relation with RE project operation schemes, which are relevant to the proposed planning model. Section III presents the proposed mathematical model for long-term RE planning. Section IV presents the case study developed in collaboration with Kasabonika Lake First Nation (KLFN), and discusses the results of applying the proposed model to develop a multiple-year RE plan considering multiple scenarios. Finally, Section V highlights the main conclusions and contributions.

## II. Electricity Rates and Subsidies

Community Applicable Electricity Rates (AERs) need to be understood in order to assess the potential benefit of RE projects in RCs. AERs in Canada vary significantly depending on the subsidy level which generally aims to set electricity prices for off-grid residents at par with the on-grid counterpart rates [5]. The details and subsidy levels differ by location; however, a generalized rate classification can be as follows:

- *Unsubsidized Customer (UbC)*: These customers pay approximately the actual cost of electricity since they do not receive a direct subsidy. These rates apply mainly to federal government clients and some community-owned buildings. This type of customers can and have installed RE equipment for Self-Consumption (SC) purposes.
- *Subsidized Customer (SbC)*: These customers pay prices that match the electricity rates of southern locations for provinces and capitals for territories. In general, these rates apply to residential customers and are approximately 10% to 20% of the actual electricity cost. Due to the highly subsidized tariff, RE is not likely to be economically feasible for these customers.
- *Avoided Fuel Cost (AFC)*: This rate does not refer to an RC customer type, but to the fuel displacement cost resulting from electricity generation, including administration and transportation costs. Hence, the AFC ultimately represents the energy cost that RE projects compete against. The rate is approximately 40% to 60% of the energy cost depending on the RC location. A Power Purchase Agreement (PPA) can be established with the utility to export RE power to the microgrid, fixing the rate to the AFC.

Similar rate structures exist in other parts of the world (e.g., [18]).

## III. Planning Mathematical Model

The main objective of this paper is to develop a multiple-year RE planning model that can help RCs determine the feasibility of energy projects considering the characteristics of remote microgrids. The model maximizes the potential benefit or social welfare $W$ perceived by the community while identifying:

- RE equipment type and capacity to be deployed;
- operation schemes under which RE units can operate;
- installation time-frame for RE equipment; and
- RE equipment location for customers whose current load demand is known.

### A. Model Architecture

Figure 1 shows the structure of the proposed model, which is composed of four stages. The input data stage includes historical data for natural resources, community location and energy-related information, and Fuel-based Generator (FG) and RE equipment specifications. The forecast stage creates the time-series estimates for the electric load, and the on-site RE resources for the planning horizon. The pre-processing stage calculates the dispatch strategy details for FGs, estimates

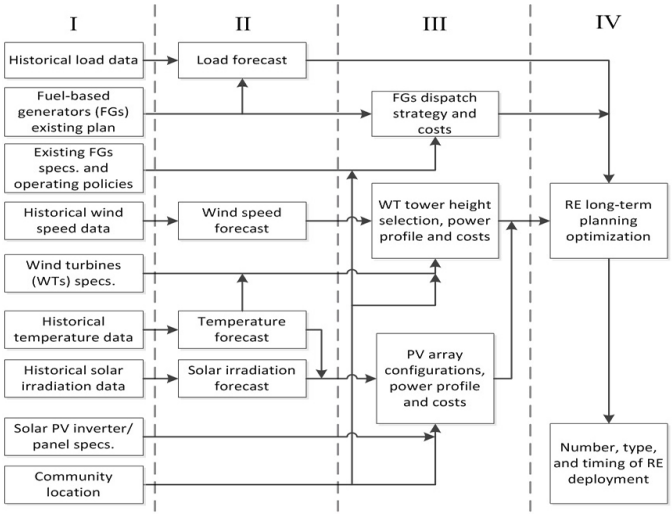


Fig. 1. Mathematical model architecture.

the power profile, pre-selects configuration details for each RE equipment type, and overall generation costs. Finally, the optimization stage solves a proposed Mixed Integer Nonlinear Programming (MINLP) problem that maximizes the RE planning social welfare for the community.

It is important to note that, based on [9], [10], battery energy storage is not considered as a viable alternative in the proposed model. Under the current conditions, battery energy storage for RCs present several challenges such as thermal management and investment and Operation and Maintenance (O&M) costs, that do not make it a feasible option in the medium term.

### B. Historical Data and Equipment Specifications

*1) Load and Installed Equipment:* Detailed historical information for the majority of RCs is available from off-grid utilities, once a community grants access to such information. The minimum data requirements for this model are the hourly load time-series and the annual electricity demand growth rate. In some cases, seasonal growth rates are preferred due to the wide load level range throughout the year. In addition, electricity consumption for large individual customers might be available for the RE planning model.

*2) Solar-related Resources:* Solar irradiation data is widely available in the literature with different levels of resolution. However, there are significant drawbacks when considering remote northern locations. Hourly solar irradiation is easily available only for sites south of latitude 58°N. In Canada, such northern sites account for approximately 100 communities and 100,000 people, covering one third of the total N&RCs. In addition, there is limited correlation between satellite and ground data for northern latitudes, which decreases the accuracy of the available data by approximately 10% to 15% [19]. Temperature data is usually available from the same sources.

*3) Wind Resource Data:* Low resolution wind speed data can be easily obtained from different sources; however, this data is usually limited to seasonal or annual averages. On-site wind speed data is seldom available for RCs; thus, synthetic meso-scale data is the next alternative data source. As with the solar resource, wind speed has the aforementioned correlation issue between ground and modelled data. The limited available studies give a significant wind speed range for northern locations, in most cases, greater than a $\pm 0.5$m/s annual average, which for some locations represents a $\pm 10\%$ difference. An additional alternative in remote locations is to obtain wind speed data from the local airport to validate meso-scale estimations; however, some remote airports do not store wind speed data and hence historical logs may not be available, as in the case of most of the communities in Northern Ontario, Canada.

### C. Forecasts

*1) Electric Load Forecast:* A historical multiple-year hourly data can be used to create a load forecast that follows the current load profile in the community. In this paper, a normal distribution function is used to perturb the existing data, based on historical annual growth rates; in some locations, seasonal growth rates can be used to more accurately represent the growth variation within a year. In addition to the historical growth, the current electric generation installed capacity in the community needs to be considered to create the forecast, since in some situations it can restrict electricity demand and eventually infrastructure growth; growth decrease, and eventual halt, may take place when the peak load is close to the FG plant rated capacity [7].

*2) Solar Irradiation and Temperature Forecasts:* Likewise to the electric load forecast, the solar and temperature forecasts are obtained by perturbing the historical hourly data by assuming a normal distribution of the annual average value for the respective parameters. In most cases, available data expands for 10 years or more; hence, a representative data sample can be used to create these forecasts.

*3) Wind Speed Forecast:* This forecast can evidently be obtained following the previous described simple forecast method; however, in some instances, historical data might be limited. In such cases, synthetic wind speed time-series can be used to create the respective forecast, as described in [20]. Such methodology is followed here to create the forecast assuming a normal distribution for the annual wind speed averages.

### D. Generation Equipment Considerations

The proposed long-term planning model requires electricity generation equipment calculations that precede the optimization step. The calculations include the dispatch strategy details for FGs and on-site available power, and Levelized Cost of Energy (LCOE) for the RE equipment under consideration, as described in the following sections.

The model equations presented next use the following sub-indexes: $j$ represents different FGs, i.e., both on-site units and those planned for future deployment; $k$ refers to different RE equipment types to be considered, i.e., solar Photovoltaic (PV) and Wind Turbine (WT); $g$ refers to complementary equipment used along with RE units, i.e., inverters for solar PV and tower options for WT equipment; $i$ represents the RE operation schemes under which projects can be installed; $t$ refers to the

year in the planning horizon; and $h$ defines the hour within a planning year.

*1) Fuel-based Generators:* The unit commitment and economic dispatch problem for FG facilities in RCs is trivial when compared to an on-grid system, simply because of the limited installed capacity and consequently less operating alternatives [21]. The dispatch strategy is determined by the operating limits in the plant Programmable Logic Controller (PLC), which simultaneously deals with the spinning reserve and the economic unit commitment problem. The PLC limits and setpoints keep approximately a 15% spinning reserve margin, as well as committing units with the minimum marginal cost, under normal operating conditions.

*2) RE Reduced Search Space:* The processing time of the proposed MINLP optimization model benefits from reducing the RE equipment search space by pre-selecting equipment units that better fit the community location. The corresponding selections for each equipment type is done by minimizing the generally used LCOE given by:

$$\min \quad LC_{k,g} = \frac{C_{TEQ_{k,g}}}{\sum_{t=1}^{ELT_k} \frac{\sum_{h=1}^{H} P_{REm_{k,g,t,h}}}{(1+r_d)^t}} \tag{1}$$

where $C_{TEQ_{k,g}}$ represents the NPV for the capital and O&M cost; $ELT_k$ is the equipment operational lifetime; $r_d$ is the discount rate; and $P_{REm_{k,g,t,h}}$ is the RE power calculated from the wind and solar equipment models, described next.

*3) Solar PV:* The solar PV pre-selection process creates feasible cost-effective solar arrays for each type of PV module type, considering the available inverters and their operating constraints such as currents and voltages, and yields the corresponding power output profiles. The main objectives are to identify the best PV array configuration for each module type and, at the same time, to reduce the search space for the optimization process. Such pre-selection is done by estimating the solar PV array total cost, given by:

$$C_{TEQ_{k,g}} = \left( C_{PVU_k} + \sum_{t=1}^{ELT_k} \frac{C_{PVOM_k}}{(1+r_d)^t} \right) x_{PVP_{k,g}} x_{PVS_{k,g}} + C_{PVINV_g} \tag{2}$$

where $C_{PVU_k}$ and $C_{PVINV_g}$ are the PV module and inverter cost, respectively; $C_{PVOM_k}$ is the annual O&M cost per module; and $x_{PVP_{k,g}}$ and $x_{PVS_{k,g}}$ are the variables representing the number of PV modules in parallel and series for each array. The RE power output for the solar PV modules in (1) is determined based on [22].

*4) Wind Turbine:* The WT pre-selection process determines the most cost-effective WT/tower height set selection for each unit type, as well as the corresponding power output profiles. The process calculates the wind speeds at the different heights and determines the total deployment costs; thus reducing, as with solar PV pre-selection, the search space during the optimization process. The WT total cost equation is given by:

$$C_{TEQ_{k,g}} = C_{WTU_k} + C_{WTTWR_{k,g}} + \sum_{t=1}^{ELT_k} \frac{C_{WTOM_k}}{(1+r_d)^t} \tag{3}$$

where $C_{WTU_k}$ and $C_{WTTWR_{k,g}}$ are the equipment cost for the WT and tower, respectively; and $C_{WTOM_k}$ is the O&M annual cost for each turbine. The WT output power calculation used in this paper follows the small WT guidelines from the International Electrotechnical Commission (IEC) 61400 standards [23].

### *E. RE Long-Term Planning*

*1) Objective Function:* The long-term planning model is an MINLP problem that maximizes the benefit to the RC, given the deployment and operational constraints of such locations. Hence, the optimization problem is defined as follows:

$$\max \quad \sum_{i=1}^{I} \sum_{t=1}^{T} \frac{W_{i,t}}{(1+RD_i)^t} \tag{4}$$

where

$$W_{i,t} = IS_{i,t} - C_{i,t} - LR_{i,t} \tag{5}$$

with $IS_{i,t}$ referring to the direct income and/or saving obtained from deploying RE equipment; $C_{i,t}$ comprises the associated project costs incurred through the planning horizon; and $LR_{i,t}$ refers to direct community economic losses encountered as a consequence of RE deployment. These variables consider the RE economic impact under different operation schemes.

As described in Section II, AERs change significantly among customer types and, evidently, these have a significant effect on potential RE deployments. Thus, the income/savings are defined as:

$$IS_{i,t} = \left( CD_i (1+r_i)^t + INC_i \right) \sum_{k=1}^{K} \sum_{h=1}^{H} P_{REu_{i,k,t,h}} \tag{6}$$

where $CD_i$ is the present electricity rate; $r_i$ is the respective annual price change; $INC_i$ is an external energy incentive, if available; and $P_{REu_{i,k,t,h}}$ is the renewable power used to supply the load, as defined later in this section.

The project costs $C_{i,t}$ comprise initial capital contributions, financial/loan, and O&M costs throughout the projects' lifetime, and is given by:

$$C_{i,t} = \sum_{k=1}^{K} (C_{CE_{i,k,t}} + C_{BPMT_{i,k,t}} + C_{OM_{i,k,t}}) \tag{7}$$

where

$$C_{CE_{i,k,t}} = C_{CAP_{i,k,t}} b_{CEP} (1 - b_{EFP}) \tag{8}$$

and

$$C_{CAP_{i,k,t}} = RC_{CAP_k} \, RP_k \, CB_{k,t} \, x_{i,k,t} \tag{9}$$

The parameters $b_{CEP}$ and $b_{EFP}$ are the percentage of available capital contribution at the start of the project, and the percentage of available external funding with respect to

the total project cost, respectively; $RC_{CAP_k}$ is the present equipment cost per kW; $RP_k$ is the equipment rated capacity; $x_{i,k,t}$ is the number of RE units to be deployed; and $CB_{k,t}$ is the Capacity Building (CB) factor. The latter represents the installation learning curve likely to be experienced at the community as more RE units are deployed, which is modelled by linearly reducing the deployment costs as additional similar units are installed; such cost reduction continues until a pre-defined minimum limit is reached. This factor is thus defined as:

$$CB_{k,t} = \begin{cases} b_{CBm} EQC_{k,t} + b_{CBb} & \text{if } EQC_{k,t} \leq b_{CBu} \\ b_{CB}^{\max} & \text{otherwise} \end{cases} \tag{10}$$

where

$$EQC_{k,t} = \sum_{i=1}^{I} \sum_{v=1}^{t} x_{i,k,v} \tag{11}$$

with $b_{CBm}$ and $b_{CBb}$ are the linear and constant cost reduction coefficients, respectively; $b_{CB}^{\max}$ is the maximum cost reduction allowed; and $b_{CBu}$ is the number of units at which $b_{CB}^{\max}$ is reached.

The available project capital ratio $b_{CEP}$ is likely to be modest, since current Aboriginal Band budgets are typically dedicated to higher priority issues, such as education, health, and infrastructure. Thus, if an RC engages in RE projects, it would require to seek external federal or provincial government funding, as well as financing instruments through, for example, bank or other institution loans, with the latter having two main positive effects from the RE project perspective: The loan is likely to increase the community's real and perceived project ownership, and creates a higher level of O&M responsibility due to the required periodic loan payment schedule. This external funding is given by:

$$C_{EF_{i,k,t}} = C_{CAP_{i,k,t}} b_{EFP} \tag{12}$$

and the loan mechanism is defined as:

$$C_{BL_{i,k,t}} = C_{CAP_{i,k,t}} - C_{CE_{i,k,t}} - C_{EF_{i,k,t}} \tag{13}$$

where

$$C_{BPMT_{i,k,t}} = C_{BL_{i,k,t}} \frac{r_B (1+r_B)^{BLT_k}}{(1+r_B)^{BLT_k} - 1} \tag{14}$$

This equation represents the generally used amortization payment equation, where $r_B$ is the interest rate and $BLT_k$ is the total number of loan payments. The O&M costs extend through the RE equipment lifetime and are given by:

$$C_{OM_{i,k,t}} = RC_{OM_k} RP_k b_{OM_t} EOS_{i,k,t} \tag{15}$$

where

$$EOS_{i,k,t} = eos_{i,k,s} = \sum_{u=1}^{T} y_{i,k,u,s} \tag{16}$$

and

$$y_{i,k,u,s} = x_{i,k,t} \quad \forall \quad \begin{array}{l} s = t, t+1, \cdots, t + ELT_k \leq T, \\ u = 1, 2, \cdots, T \end{array} \tag{17}$$

The parameter $RC_{OM_k}$ is the present O&M cost per kW, and $b_{OM_t}$ is the cost variation through the equipment's operational lifetime, which is likely to increase in later years. In addition, $EOS_{i,k,t}$ represents the number of units on-site, and $y_{i,k,u,s}$ is an auxiliary variable relating $EOS_{i,k,t}$ to $x_{i,k,t}$.

Some RCs could experience a potential revenue loss $LR_{i,t}$ as a direct consequence of RE deployment. This economic loss is incurred if the community is the sole or partial fuel supplier for the utility company. This loss of community revenue due to fuel displacement is given by:

$$\begin{aligned} LR_{i,t} = & r_{FR} C_{FUEL} b_{CFP_t} (1 + CPI)^t) \\ & \left(f_{BASE_t} - f_{PROJ_t}\right) z_{i,t,h} \end{aligned} \tag{18}$$

where $r_{FR}$ is the percentage of fuel revenue obtained by the community; $C_{FUEL}$ is the actual on-site fuel price; $b_{CFP_t}$ is the percentage of the total fuel supply purchased from the community; $CPI$ is the customer price index fuel price growth; $f_{BASE_t}$ is the fuel consumption of the baseline scenario, i.e., with no RE equipment installed; $f_{PROJ_t}$ is the expected fuel consumption after RE equipment deployment; and $z_{i,t,h}$ is the ratio of RE used for each operation scheme, which is defined as:

$$z_{i,t,h} = \frac{\sum_{k=1}^{K} P_{REu_{i,k,t,h}}}{\sum_{i=1}^{I} \sum_{k=1}^{K} P_{REu_{i,k,t,h}}} \tag{19}$$

The fuel consumption for the baseline and project scenarios are represented by:

$$f_{BASE_t} = \sum_{j=1}^{J} \sum_{h=1}^{H} (d_{GSa_j} P_{FG_{BASE_{j,t,h}}} + d_{GSb_j}) \tag{20}$$

and

$$f_{PROJ_t} = \sum_{j=1}^{J} \sum_{h=1}^{H} (d_{GSa_j} P_{FG_{proj_{j,t,h}}} + d_{GSb_j}) \tag{21}$$

where $d_{GSa_j}$ and $d_{GSb_j}$ represent the linear and constant coefficients for fuel consumption vs. power relationship; since the rated power of such generators is relatively low (< 2MW), a linear approximation is adequate for planning purposes.

*2) Model constraints:* The power per generator for the baseline and project scenarios $P_{FG_{BASE_{j,t,h}}}$ and $P_{FG_{proj_{j,t,h}}}$ are calculated by:

$$P_{FG_{t,h}} = P_{D_{t,h}} - \sum_{i=1}^{I} \sum_{k=1}^{K} P_{REu_{i,k,t,h}} \tag{22}$$

where $P_{D_{t,h}}$ represents the community load demand.

There are three categories of RE power used in the proposed planning model: The available RE power $P_{REa}$ is the calculated power output from the respective wind and solar model. The RE used power $P_{REu}$ is the expected power to be consumed by the community. Finally, the curtailed RE

power $P_{REc}$ is the excess power resulting from the dispatch constraints for RE equipment. These RE dependant variables are given by:

$$P_{REu_{i,k,t,h}} = P_{REa_{i,k,t,h}} - P_{REc_{i,k,t,h}} \tag{23}$$

$$P_{REa_{i,k,t,h}} = P_{REm_{k,t,h}} EOS_{i,k,t} \tag{24}$$

$$P_{REc_{i,k,t,h}} = \begin{cases} P_{DB_{i,t,h}} & \text{if } P_{DB_{i,t,h}} > 0 \\ 0 & \text{otherwise} \end{cases} \tag{25}$$

where $EOS_{i,k,t}$ is determined in (16) and

$$P_{DB_{i,t,h}} = \sum_{k=1}^{K} P_{REa_{i,k,t,h}} - P_{D_{i,t,h}} + d_{GSLIM_{i,t}} \tag{26}$$

$$d_{GSLIM_{i,t}} = (1 - CT_i) d_{GS}^{\min} RP_t^{\min} \tag{27}$$

$$P_{D_{i,t,h}} = P_{D_{t,h}} b_{D_i} \tag{28}$$

with $P_{DB_{i,t,h}}$ representing the difference between the available renewable power and the respective load; $d_{GSLIM_{i,t}}$ is the FG lower limit at which, when reached, RE is curtailed; $CT_i$ is a pre-defined binary constant used to distinguish between RE curtailment classes, with $CT_i = 1$ representing the case when RE is only for SC (no grid feeding), and $CT_i = 0$ representing the case when RE can inject power to the grid; $d_{GS}^{\min}$ is the minimum FG load ratio; $RP_t^{\min}$ is the rated power of the smallest FG; and $b_{D_i}$ is the load ratio of the total demand for each customer $i$ where $\sum_{i=1}^{I} b_{D_i} = 1$. The distinction between curtailments in the model is based on previous RE northern projects. Thus, $CT_i = 1$ involves disconnecting the RE source from the microgrid to avoid sending any power to the distribution system; this has been the case of certain SC projects, since no contract with the utility was in place to allow electricity export (3 SC projects in northern Ontario have been supported in the last few years [24]). On the other hand, $CT_i = 0$ allows for microgrid export, as long as the lower operating limit for the smallest FG unit is not reached [3]. It should be mentioned that in northern RCs there is the potential for using the curtailed RE for thermal storage and/or space heating [25]; however, this particular option is not considered in this paper.

The intended RE installed capacity is likely to encounter limits set by the utility to avoid any disruptions to the existing microgrid system. In the Northwest Territories, for example, this RE installed capacity restriction has been set as a percentage of the RC annual average load. Hence, this constraint is modelled as:

$$\sum_{i=1}^{I} \sum_{k=1}^{K} RP_k EOS_{i,k,t} \leq b_{IC_t}^{\max} \frac{\sum_{h=1}^{H} P_{D_{t,h}}}{H} \tag{29}$$

where $b_{IC_t}^{\max}$ is the maximum RE installed capacity ratio.

The economic feasibility of the planning scenario is given by the combined result of the NPV and the Internal Rate of Return (IRR). In the model, NPV is directly accounted for as part of the social welfare objective function (4). However, maximizing $W_{i,t}$ does not necessarily mean that the project is financially attractive; thus, the project's resulting IRR must be moderately above the pre-defined discount rate to appeal to the involved stakeholders. This constraint is given by:

$$\sum_{t=1}^{T} \frac{W_{i,t}}{(1 + IRR_i)^t} = 0 \quad \forall \quad \sum_{k=1}^{K} \sum_{t=1}^{T} x_{i,k,t} \geq 1 \tag{30}$$

where $IRR_i^{\min} \leq IRR_i \leq IRR_i^{\max}$. The parameter $IRR_i^{\min}$ defines the minimum required to consider financial project feasibility. The upper limit $IRR_i^{\max}$ is only to be implemented if an incentive program is available (e.g., a Feed-In-Tariff (FIT) program), the incentive rate aimed at making RE projects financially feasible within a desirable IRR range.

RE projects for the same equipment type and operation scheme are likely to be funded and deployed only once over the planning horizon. This consideration avoids repeating project activities in different planning years, such as equipment transportation for the same project over two different years or decommissioning. This constraint is given by:

$$x_{i,k,t} = EOS_{i,k,t} \quad \forall \quad x_{i,k,t} > 0 \tag{31}$$

### *F. Financial Indicators*

The proposed model uses various financial indices at different stages to quantify the economic feasibility of the proposed projects. The main index is the NPV of the social welfare $W$ in (5), which the model aims to maximize, so that the community best benefits from RE deployment projects. However, on its own, the social welfare does not assure that the proposed projects are financially attractive, since the resulting $W$ may not cover the operating and financial expenses over the project lifetime. Hence, the financial return represented by the IRR index for each type of project is bounded between appropriate limits in (30) to guarantee appropriate returns on investments. Furthermore, the proposed model considers RE equipment that produces the highest cost/benefit return through the minimization of the LCOE for each type of technology under consideration, as per (1). Overall, the intention of the financial indices is to obtain not only technically but financially feasible scenarios that can be currently implemented in RCs.

## IV. Case Study: Kasabonika Lake First Nation

The case study aims to apply the model to create a multiple-year RE plan for KLFN, an Oji-Cree First Nation community located in northern Ontario, 53° 31' 59"N and 88° 36' 21"W. The KLFN diesel plant consists of three generators, rated at 400 kW, 600 kW, and 1 MW, using a single-unit dispatch strategy under normal operating conditions. Currently, the community and utility have plans to increase capacity by installing a 1.6 MW generator likely over the next year. The local utility and community are rather familiar with RE projects, since WT and solar PV units have been deployed. The detailed information obtained for this case study is based on the collaboration efforts among Hydro One Remote Communities Inc. (HORCI), the community, and the authors.

TABLE I
CASE STUDY PARAMETER VALUES

| Param. | | Value | Param. | | Value |
|---|---|---|---|---|---|
| $b_{CB}^{\max}$ | (%) | 20 | $C_{FUEL}$ | ($/litre) | 1.85 |
| $b_{IC_t}^{\max}$ | (%) | 50 | $CPI$ | (%) | 4.5 |
| $b_{CBu}$ | | 20 | $d_{GS}^{\min}$ | (%) | 40 |
| $b_{CBm}$ | | -0.01 | $d_{GSLIM_{i,t}}$ | (%) | 40 |
| $b_{CBb}$ | | 1.01 | $ELT_k$ | (years) | 15 |
| $b_{CEP}$ | (%) | 10 | $INC_i$ | ($/kWh) | 0 |
| $b_{CFP_t}$ | (%) | 0 | $IRR_i^{\min}$ | (%) | 8 |
| $b_{EFP}$ | (%) | 50 | $RD_i$ | (%) | 6 |
| $b_{OM_t}$ | (%) | 0 | $r_{FR}$ | (%) | 10 |
| $BLT_k$ | (years) | 15 | $RC_{CAP_k}$ | $/W | 9[c] 12[d] |
| $CD_i$ | ($/kWh) | 0.926[a] 0.394[b] | $RP_t^{\min}$ | (kW) | 400[e] 600[f] |

[a]Unsubsidized electricity rate.
[b]Avoided fuel cost rate.
[c]Solar PV cost, [d]WT cost.
[e,f]Before and after the 400 kW FG is decomissioned.

The solar PV panels considered are: 230 $kW_p$ Kyocera, 220 $kW_p$ Sanyo, and 230 $kW_p$ and 240 $kW_p$ Canadian solar modules. The solar inverters are: 6.3 kW SMA, 10 kW Fronius, 10 kW Mastervolt, and 10 kW Aurora/PowerOne. And, the WTs used are: 50 kW Endurance; 60 kW, 95 kW, and (2x) 100 kW Northern Power; 30 kW Wenvor; and 10 kW Bergey WTs. The equipment was selected since these units are commercially available in Canada and can potentially be transported to the community (e.g., winter roads).

The objective of the case study is to determine the most feasible RE alternatives over a 20-year planning horizon, considering a project investment period of 5 years. The operation schemes are: SC for the community-owned buildings where load data is available (i.e., school and water treatment plant), and AFC for the rest of the load. Table I presents the parameters used for all scenarios in the case study, which were obtained from KLFN, HORCI, and historical estimates. In addition, the model assumes that project investments take place at the start of each year, while their operation does not start until middle of the year. The model is implemented in MATLAB using a genetic algorithm from the Global Optimization Toolbox to solve the MINLP problem.

Table I shows the capital costs $RC_{CAP_k}$ associated with the deployment of solar PV and WT equipment used in this study. These capital costs are based on information from previous RE equipment deployed in the last two years at KLFN, which due to the location of the community, are higher than RE deployment costs in more accessible locations. Thus, for solar PV in Canada, the average price for on-grid turnkey projects ranged between $2,800/kW and $5,000/kW, but for off-grid systems it was $8,100/kW in 2012 [26]. In the case of WTs in Canada, the average cost for turnkey large WTs projects was $2,259/kW in 2013, while for small on-grid WT the average price ranged between $6,000/kW and $8,000/kW in 2008 [27], [28]. Note that the WT selection criteria must consider the wind regime; hence, in the case of KLFN, due to its low wind potential, a commercial WT was selected to make WTs economically feasible (e.g., Class 3 WT). For RCs with higher wind speed regimes, different WT classes would have to be considered in the planning process.

### A. Scenarios

The following studied scenarios are based on some of the alternatives and parameters of concern while planning RE project(s) in RCs:

- *Funding alternatives ($b_{CEP}$ and $b_{EFP}$)*: Scenario 1 considers the baseline where one stakeholder funds the total projects' cost. Scenario 2 incorporates a loan alternative to finance the projects, since initial economic resources are likely to be limited. Scenarios 3-12 considers the loan alternative plus external government funding aimed to promote northern development available for community-driven projects.
- *Discount rate ($r_d$):* Scenario 3 considers the social discount rate of 4% used by the Ontario Power Authority (OPA) for project assessment. Scenarios 4 and 5 consider higher discount rates, 6% and 8%, respectively, to assess the higher risk or uncertainty of future cash-flows. For the rest of the scenarios, a discount rate of 6% was used.
- *Fuel cost growth ($CPI$)*: Scenario 6 considers a 5% annual growth rate for the diesel-fuel cost which is equal to the historical average of the 10-year compound growth rate for fuel prices in northern Ontario since 2000. Scenario 7 considers a higher rate, 7% cost growth, and all other scenarios use a 4.5% annual growth, the 5-year historical compound growth rate.
- *RE capacity limit ($b_{IC_t}^{max}$)*: Scenario 8 eliminates the installed capacity constraint described in (29). For all other scenarios, the RE installed capacity limit is set to 50% of the annual average community load.
- *Solar irradiation*: Scenarios 9 and 10 represent the respective lower and upper expected variation limits for the annual average solar global irradiation. Based on the correlation data available for a similar latitude location, the variation considered is approximately $\pm 6\%$. For the rest of the scenarios, an annual average of 2.9 kWh/m$^2$/day is assumed.
- *Wind speed*: Scenarios 11 and 12 analyze the effect of lower and higher wind speeds, $\pm 10\%$; however, based on the meso-scale correlation information and performance of the currently installed WTs, the actual value is closer to the lower bound. The rest of the scenarios are based on an annual average of 5.61 m/s.

### B. Results

Each scenario gives a multiple-year RE plan for the community. A detailed explanation of Scenario 3 that encompasses all the available options of the model is first presented. Followed by a general discussion of the twelve selected scenarios.

*1) Scenario 3:* This is the first scenario that considers the diverse funding mechanisms which are likely to be available for community-driven RE projects. Hence, this scenario shows the capabilities of the proposed model, highlighting the benefits of assessing multiple projects over a planning horizon. Figure 2 (a) shows the solar PV cost reduction over the years resulting from the CB process considered by the model, which intrinsically promotes further solar PV deployment. Figure 2 (b) presents the proposed installed capacity for each

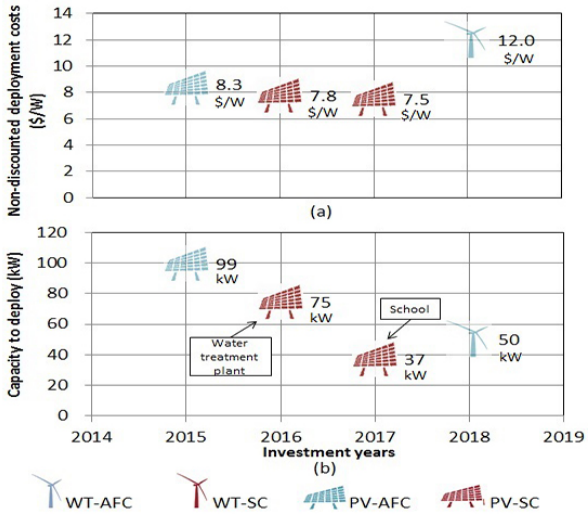


Fig. 2. Scenario 3. RE long-term plan: (a) deployment costs and (b) capacity.

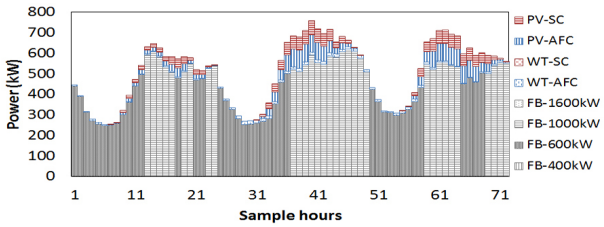


Fig. 3. Power output per generator type for Scenario 3 (June 23th-25th).

type of project and operation scheme; in this case, both SC and AFC schemes are economically feasible, and since the loads for the water treatment plant and the school are known, the capacities at such locations can also be identified. The total planned RE capacity is 260 kW, which corresponds to approximately 47% of the annual average load (the maximum RE installed capacity limit was set to 50%).

Figure 3 presents the power supplied per type of generation unit for 3 sample days; the FG units switch accordingly between high and low load requirements, as expected, where RE can be considered a negative load due to the low penetration level, having a maximum hourly and highest annual RE contributions of 35% and 7% over the planning horizon, respectively.

Figure 4 shows the components of the annual social welfare $W$ over the planning horizon. First, the combination of the external funding and the loan alternatives assure that the initial cash contribution from the community remains low, so that RE projects do not compete with other priority projects within the community. Second, the RE projects bring a direct benefit to the community, since they will be the equipment owners; such benefit comes with the responsibility of covering the loan repayment schedule. The intention of the loan is not only to obtain financial feasibility, but also to be a commitment to maintain the equipment operational and invest in the relatively high O&M costs, which in this case corresponds to approximately \$0.09/kWh and \$0.15/kWh for the solar PV and WT equipment, respectively.

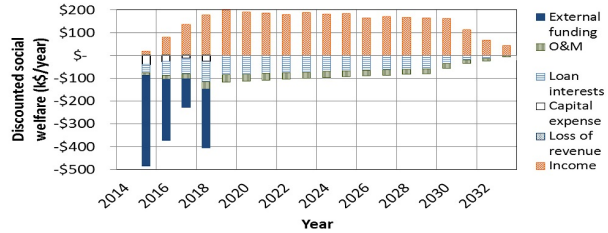


Fig. 4. Cash-flow for Scenario 3.

*2) Summary of All Scenarios:* Figure 5 shows the proposed RE deployed capacity by technology and operating scheme for each scenario. Scenarios 1 and 2 are the most limited with 100 kW of installed capacity, since the investments are not distributed among different funding alternatives, and as a result only PV-SC projects are marginally feasible. Scenarios 3 to 12 consider external funding, thus reducing the community project expenses, and resulting in higher feasible RE deployment capacities. For these scenarios, the selection of the discount rate value has the highest effect in the RE capacity output. Hence, the social discount rate of 4% allows for 274 kW of RE deployment, while the more conservative 8% discount rate only allows for 236 kW; this reduction is mainly seen in the AFC operating scheme. Scenarios 6 and 7 show that changing the compound annual fuel growth rate from 5% to 7% has an installed capacity difference of only 12 kW; the reason for the relatively minor change is that the current subsidy framework decreases the direct effect of fuel price in the electricity rate. Scenario 8 proposes RE projects of 300 kW capacity when no pre-defined installed capacity limit is set, which corresponds to $b_{IC_t}^{\max} = 54\%$; hence, there is no further economic benefit of increasing RE capacity beyond this level under current operating conditions. Scenarios 9 and 10 show that even with the potential solar irradiation variation, the expected RE installed capacity is maintained at 274 kW. Finally, Scenarios 11 and 12 show that WT technology is not feasible when considering the expected variation in annual wind speed; if the actual wind speed decreases by 10%, WT technology is not included in the deployment plan. Note that for all scenarios presented, the technological risks are similar, since the type of equipment to be deployed is the same and only the RE installed capacity changes.

Figure 6 presents the IRR values from the community perspective for each type of project and scenario. Scenarios 1 and 2 have relatively low IRR values without even considering the parameter variation of the remaining scenarios, and as a result are not attractive alternatives. On the other hand, Scenarios 3 to 12 have significantly higher IRR, due to the partial contribution of 50% of the capital expenses coming from the government agency, and thus the community capital costs are halved, while still obtaining the total economic benefit from the proposed projects. Furthermore, due to the same funding contribution, the potential loan is also reduced for Scenarios 3 to 12, which also reduces the annual loan payments and thus further contributes to an increase in the IRR values. This figure also shows the IRR for the received government funding when considering that government fuel

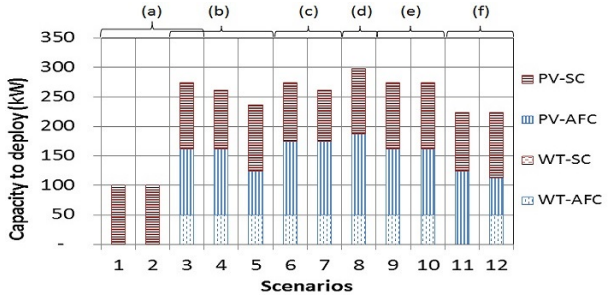


Fig. 5. Proposed RE deployment capacity per scenario: (a) funding alternatives, (b) discount rates, (c) fuel costs, (d) no RE deployment limit, (e) solar irradiation levels, and (f) wind speed levels.

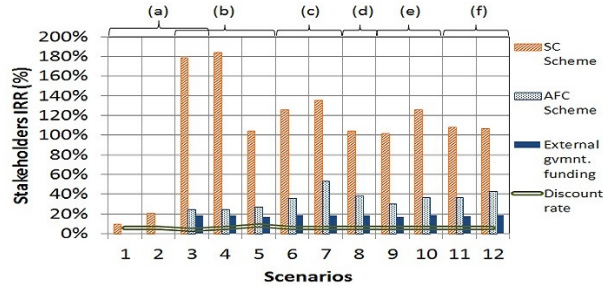


Fig. 6. Expected IRR per stakeholder and scenario: (a) funding alternatives, (b) discount rates, (c) fuel costs, (d) no RE deployment limit, (e) solar irradiation levels, and (f) wind speed levels.

subsidies are also reduced. In Ontario, approximately 66% of the total fuel cost in HORCI operated communities comes from a provincial government subsidy; hence, if RE generation reduces fuel consumption, the total subsidy contribution from the government will also be modestly reduced. Therefore, from a policy perspective, supporting such remote RE projects would also benefit the government on top of other social benefits. It should be noted that as RE is further integrated into RCs, there will be a need to account for the potential benefits in the rate structure itself; this would require further study, and is not addressed in this paper.

## V. Conclusions

A novel RE long-term planning model for RCs has been presented in this paper. The proposed model can be used to evaluate several RE projects through multiple-years to obtain a long-term plan regarding RE development in RCs. The proposed model considers different operation schemes under which RE can be deployed, considering current economic and technical constraints. Furthermore, it considers community funding alternatives which results in higher economic feasibility for the community by sharing the risk among stakeholders. Finally, the model also allows quantifying the government benefit from supporting such projects under a given energy subsidy framework.

The results demonstrate that realistic RE community plans can be obtained with the proposed model, considering wind and solar equipment that have or can be deployed and operated in such remote locations, while producing a direct economic benefit to the community. The model should be applicable to RCs in jurisdictions with similar characteristics as Canadian RCs, such as in Alaska and Chile.

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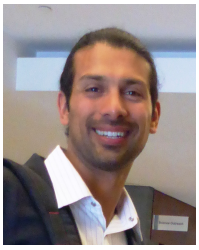

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