# 1 Introduction

This document details the modeling assumptions for the dGen Model, focusing primarily on the most significant factors for interpreting model results. It is separated into three major sections, based on their priority in driving model results:

* Economic Drivers of Customer Adoption
* Non-Economic Drivers of Customer Adoption
* Additional Model Assumptions

Under each section, individual assumptions are described under separate subheadings. For each assumption, the following information is provided:

* A brief summary
* Current default settings for the assumption
  + If applicable, these settings are broken out into two sets, one for “near-term” assumptions (years 2014-2020), and one for long-term (2020-2050)
  + Assumptions with substantial uncertainty or insufficient empirical support are marked with an asterisk and discussed in the “future work” section
* A discussion of planned future work to improve or further support default settings

# 2 Economic Drivers of Customer Adoption

### 2.1 System Financing

#### Summary

dGen Model agents may finance a DER system via either a loan (for host-owned system) or a lease (for third-party-owned systems). Each of these financial structures is parameterized in the model with multiple user-defined inputs:

* Host-owned:
* Loan rate, loan term (length in years), down payment percent, discount rate, and tax rate
* Third-party-owned: Lessor hurdle rate, lease term (length in years), discount rate and tax rate

All inputs can be customized for different market sectors (i.e., residential, commercial, industrial) and model years.

#### Default Settings (2014 - 2020)

The default settings for financing assumptions by sector are detailed in the tables below. These settings are based on current market conditions, which have remained fairly stable for several years. Therefore, they apply for model years 2014-2020.

These settings are based on…

* Commercial/industrial Loans: Based on a 12-year historical average of real yields of corporate bonds rated Aa and A by Moody’s (SIFMA 2010).
* Residential Loans: Based on a 3-year historical average of real rates for $30,000 U.S. home equity loans. Accessed January 20, 2010: [www.wsjprimerate.us/home\_equity\_loan\_rates.htm](http://www.wsjprimerate.us/home_equity_loan_rates.htm).
* Leasing hurdle rate and term\*:
  + Some source..?
* Discount Rate

Default Financing Assumptions for Host-Owned Systems by Sector

|  |  |  |  |
| --- | --- | --- | --- |
| Market Segment | Residential | Commercial | Industrial |
| Loan Rate | 6% | 6% | 6% |
| Loan Term (years) | 15 | 20 | 20 |
| Down Payment | 20% | 20% | 20% |
| Discount Rate | 10% | 12% | 12% |
| Tax Rate | 33% | 35% | 35% |

Financing Assumptions for Third-Party-Owned Systems by Sector

|  |  |  |  |
| --- | --- | --- | --- |
| Market Segment | Residential | Commercial | Industrial |
| Lessor Hurdle Rate | 10% | 10% | 10% |
| Lease Term (years) | 20 | 20 | 20 |
| Discount Rate (Lessee) | 10% | 12% | 12% |
| Tax Rate | 33% | 35% | 35% |

#### Future Projections (2022 - 2050)

Add tables giving assumptions and supporting text here

#### Planned Future Work:

We plan to acquire additional empirical support for and potentially refine the settings for both current and future leasing hurdle rates by… talking to existing lessors of wind (united wind?), reviewing historical lease terms for solar (research by Davidson, etc.)?

### 2.2 System Installation Costs

#### Summary

Distributed wind system installation costs are comprised of three components: capital costs (in $/kw), default tower height (hub height in m), and cost for higher towers above the default height ($/kw/m). Costs are input to the model separately for each of the 11 rated turbine sizes (2.5, 5, 10, 20, 50, 100, 250, 500, 750, 1000, and 1500 kw) and for each model year. Overall the model considers 23 different combinations of turbine height (m) and rated size (kw); the use of a default tower height and cost adder for taller towers simplifies the user interface.

#### Default Settings (2014)

Initial system costs for the first model year (2014) are detailed in the table below.

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Turbine Rated Power (kW)** | **Adjusted Cost ($/kW)** | **Installed Cost**  **($)** | **Minimum Hub Height (m)** | **Marginal Tower Cost ($/[kW\*m])** |
| 2.5 | $10,045 | $25,113 | 20 | $211 |
| 5 | $7,785 | $38,925 | 30 | $164 |
| 10 | $6,914 | $69,145 | 30 | $118 |
| 20 | $6,459 | $129,186 | 30 | $71 |
| 50 | $5,858 | $292,879 | 30 | $15.7 |
| 100 | $5,402 | $540,238 | 40 | $11.3 |
| 250 | $3,525 | $881,232 | 50 | $10.8 |
| 500 | $2,961 | $1,480,283 | 50 | $9.9 |
| 750 | $2,630 | $1,972,827 | 50 | $9.0 |
| 1,000 | $2,396 | $2,396,206 | 80 | $8.1 |
| 1,500 | $2,185 | $3,277,628 | 80 | $6.4 |

NREL determined these costs through detailed analysis, presented thoroughly in the dGen documentation (add reference),

NREL determine these costs by examining several data sets to determine the median installed cost for each size of turbine (rated power) as well as the most common hub heights for each size. Data sets including in our analysis include: a non-public database of project-level characteristics funded under the US Department of Treasury 1603 program, … . We used median costs, rather than mean costs, to minimize bias caused by data outliers. For each rated turbine size, this median cost was assumed to apply to the most common hub height for that size. The procedure used to develop the costs is summarized in the figure below.

To keep the model run times reasonable, dGen offers only a few tower heights (in 10-m increments). For each turbine size, the tower height range determined from the data was adjusted to fit these increments. The marginal tower height costs were used to develop an estimated installed cost for a turbine using the shortest tower height allowed for each turbine size. We then plotted the installed cost versus the log of the rated power and determined the best fit line and then used that result to determine the adjusted costs for each turbine size at the minimum tower height used in the model.

Our cost data sets do not provide sufficient resolution to determine the marginal cost of taller towers. As a result, we consulted with various tower wholesalers, distributed original equipment manufacturers, and project developers for this information. We obtained sufficient data for the small and utility size ranges but collected little data for turbines of 250 to 750 kW. The available data were then used to develop a marginal tower height cost adjustment for each turbine size provided in the model.

#### Future Projections (2016 – 2050)

[ need to come up with a justification for this ]Default Settings (2014-20

* + Initial costs
  + Cost Projections
* System Operation and Maintenance Costs
* Power Curves and Performance Improvement Schedule
  + Wind gross generation derate (0.85 standard default, cite wind vision and other studies)

No additional work is planned at this point.

* + Default Values:
  + Sources:
  + Limitations/Concerns:
  + Planned Future work:
  + By business model, sector, and year
  + Depreciation schedule
  + Inflation
    - 2.5%
* Load Growth
  + AEO2015 Reference Case
* Rate Escalations
  + AEO2015
    - Constant rate of growth after 2040/2050?
    - Second period of market acceleration around 2030?
  + AEO2015 Extended
    - Time-series projection of rate of growth after 2040/2050? – compounding
* Rate Tariffs
  + Source and Types
  + How selected for each customer
    - Frequency of different types
  + How calculated
    - SAM
* “Policies”
  + State Incentives
    - DSIRE – requires update (with Data from alice?)
    - Add SRECS?
    - Assumed year of expiration?
    - Assumed duration?
  + Federal incentives
    - ITC – expiration assumptions?
  + Net Metering
    - Explain or reference how SAM does NEM?
    - BAU case – system size limits and projected year of expiration?
      * Source
      * Do we need to update expirations for wind instead of solar?
    - Wholesale or avoided costs for non-NEM
      * Justification and Sources
    - Net or Gross Feed in Tariff?
* Maximum Market Share to Economics Curves
  + TPO – NREL
  + HO – Navigant????
  + Importance of sensitivities here…

# 3 Non-Economic Drivers of Customer Adoption

* Sizing targets
  + NEM and nonNEM
  + Sources? (only wind source is NY data, showing 75% sizing. Solar sizing tends to be higher – 90-95%)
* Existing market deployment (2012)
  + Based on state-level data by system size from PNNL
  + Disaggregated to sectors based on turbine size
  + Disaggregated to counties and agents based on solve-year 2014 economics
* Bass Diffusion parameters
  + Do we need to calibrate p/q and TEQ for year 1? (similar to work for solar)
    - TEQ yr 1 will not be possible until we gain approval of the rest of our default settings
* Maximum Market Potential (number of potential customers)
  + Residential – single-family owner occupied homes only
  + Commercial – owner and non-owner occupied buildings, all commercial customers

# 4 Additional Model Assumptions

* Uncertainty in model results
  + I think we should plan to include Monte Carlo simulation for final model runs
* Competition with Other DG Technologies
  + Existing beta capability for market competition with Solar, fairly untested at this point
* Business Models
  + TPO and HO only
  + No community solar
* Availability of Third Party Ownership by State and Year
  + Existing availability (source – solar?)
  + Future projections of availability
* Siting Considerations
  + Data sources and Logic
  + Default settings and logic