# 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:

* An indication whether the assumption is specific to wind or technology agnostic (i.e., also used in solar modeling)
* A brief summary
* Current default settings for the assumption
  + If applicable, these settings are broken out into separate discussions by time period (e.g., near-term and future projections)
  + 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 (Wind-Specific)

#### 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 near-term 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 (Wind-Specific)

#### Summary

Distributed wind system installation costs are parameterized in dGen with three inputs: capital costs ($/kw), default tower height (hub height in m), and marginal costs for higher towers above the default height ($/kw/m). Costs are customizable for each rated turbine size (2.5, 5, 10, 20, 50, 100, 250, 500, 750, 1000, and 1500 kw) and model year.

#### Default Settings (2014)

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

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Turbine Rated Power (kW)** | **Adjusted Cost ($/kW)** | **Installed Cost**  **($)** | **Default (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 a methodology described in detail in the dGen documentation (Appendix B, Section B4) (Sigrin et al., 2015). In summary, this analysis included:

1. Reviewing and analyzing multiple data sets with project cost information and determining adjusted costs ($ per kw of rated power) for each of the 11 turbine sizes evaluated in the model. Specific data sources used include:

* A non-public database of project-level characteristics funded under the US Department of Treasury 1603 program
* … .

1. Interviewing several turbine and tower manufacturers to determine tower prices for various turbine sizes, then fitting a piecewise, best-fit curve to the empirical data to estimate marginal tower height costs. Only sparse data was available for turbines in the range of 250-750 kw. Industry sources for data included: … .
2. Adjusting project cost data from step 1 using the marginal tower height costs from step 2 to determine adjusted costs for each turbine size at the default (minimum) hub height.

#### Future Projections (2016 – 2050)

[ need to come up with a justification for this ] [ learning curves?]

#### Planned Future Work:

We plan to perform the following work to develop further empirical support for the following assumptions:

1. Marginal tower height costs for mid-size turbines (250-750 kw)

* Add description

1. Future projections of costs

* Add description

## 2.3 System Operation and Maintenance (O&M) Costs (Wind-Specific)

#### Summary

The dGen model considers two types of O&M costs: scheduled (i.e., preventative) and unscheduled (i.e., repair) maintenance costs. Both of these costs are treated as fixed annual costs and given in terms of the $/kw. The model assumes no variable O&M costs because … . Fixed O&M costs are input to the model separately for each turbine rated size (kw) and model year.

#### Default Settings (2014)

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

Operation and Maintenance Cost Assumptions

|  |  |  |  |
| --- | --- | --- | --- |
| **Turbine**  **Rating (kW)** | **Total Fixed O&M ($/kW)** | **Scheduled Maintenance ($/kW)** | **Unscheduled Maintenance ($/kW)** |
| 2.5 | $38.94\* | $27.64 | $11.30 |
| 5 | $38.92\* | $27.62 | $11.30 |
| 10 | $38.88 | $27.58 | $11.30 |
| 20 | $38.80 | $27.50 | $11.30 |
| 50 | $38.56 | $27.27 | $11.29 |
| 100 | $38.15 | $26.87 | $11.28 |
| 250 | $36.94 | $25.69 | $11.25 |
| 500 | $34.91 | $23.71 | $11.20 |
| 750 | $32.89\* | $21.74 | $11.15 |
| 1,000 | $30.86\* | $19.76 | $11.10 |
| 1,500 | $26.81\* | $15.81 | $11.00 |

NREL derived these estimates for fixed O&M costs through statistical analysis of O&M estimates provided by a variety of sources, including manufacturers (add refs), leasing companies (add refs), installers (add refs), and consultants (add refs). Specifically, NREL fit a linear regression to the various cost estimates, predicting scheduled and unscheduled maintenance costs as a function of turbine rated size.

Appendix B, Section B4 of the dGen Model Documentation (Sigrin et al. 2015) provides a detailed discussion of the caveats and limitations of cost estimates received. The primary weaknesses noted in this document are:

1. Total lack of data for unscheduled maintenance for small turbines less than 10 kw
2. Minimal data for unscheduled maintenance for turbines > 660 kw.
3. The single best-fit regression line may not account for important mechanical transitions in turbine design around 2.5 and 50-100 kw that may affect O&M costs in a non-linear fashion.

#### Future Projections (2016 – 2050)

[ need to come up with plan and justification for this ]

#### Planned Future Work:

In order to better support the caveats noted above, we plan to perform a second round of O&M data collection and interviews, focused primarily on the extreme sizes (2.5-5 kw and 750-1500 kw), where initial empirical support was lacking. In addition, if we are able to increase sample size sufficiently, we may try to split the data at the system sizes corresponding to important mechanical transition and fit separate regressions for each subset of data.

## 2.4 Current and Future Technology Performance (Wind-Specific)

### Summary

The dGen model uses eight turbine power curves to represent differences in turbine performance across size classes and into the future. Users of the model must assign one of the power curves to each of the turbine size classes (2.5 – 1500 kw) and model years (2014 – 2050). This approach allows for transitions in turbine performance over time and across size classes at varying rates.

### Default Settings (2014)

Four of the eight power curves in the dGen model are used to represent current (2014) wind turbine technology. NREL derived these power curves using the methodology detailed in Appendix B, Section B2 of the dGen Model Documentation (Sigrin et al. 2015). This process was based on a detailed review and subsequent analysis of existing turbine power curves, spanning the range of turbine sizes used in the model. Data sources used in this review include: … . This analysis resulted in four generic power curves, each associated with a different size class, outlined in the table below:

|  |  |  |  |
| --- | --- | --- | --- |
| Power Curve | Rotor Efficiency | Capacity Factor | Power Curve ID |
| Current Small Residential (2.5‑20 kw) | 3.07 m2/kWp | 29.0% | 1 |
| Current Small Commercial (50‑100  kw) | 4.9 m2/kWp | 37.5% | 2 |
| Current Midsize (250‑1000 kw) | 3.1 m2/kWp | 42.0% | 3 |
| Current Large (1500 kw) | 4.9 m2/kWp | 38.5% | 4 |

NREL uses these power curves as the default settings for the first model year (2014).

### Future Projections (2016 – 2050)

The remaining four turbine power curves used in the dGen model were derived by NREL to represent future technology performance in both the near term (5 – 15 year) and long term (10 – 35). These power curves were derived based assumptions about the maturity of existing technology at different turbine size classes, along with engineering judgment regarding the technical factors limiting future technology improvements. Refer to Appendix B, Section B2 of the dGen model documentation for a thorough description of the methodology and assumptions used in development of these four power curves. The resulting near and far future power curves are described in the table below.

|  |  |  |  |
| --- | --- | --- | --- |
| Power Curve | Rotor Efficiency | Capacity Factor | Power Curve ID |
| Near Future Small Residential (2.5‑20 kw) | 4.0 m2/kWp | 38.5% | 5 |
| Far Future Small Residential (2.5‑20 kw) | 5.2 m2/kWp | 40.0% | 6 |
| Near Future Small Commercial, Midsize, and Large (50-1500 kw) | 4.2 m2/kWp | 43.0% | 7 |
| Large (1500 kw) | 5.2 m2/kWp | 44.0% | 8 |

Although the names of the power curves indicate their applicability to general time periods (current, near future, far future), the schedule by which transitions between power curves occurs is defined on an annual basis. NREL determined the default settings for the schedule of power curve transitions by … . The default settings for power curve transitions are show in the table below.

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Turbine Size (kw)** | **2014** | **2016** | **2018** | **2020** | **2022** | **2024** | **2026** | **2028** | **2030** | **2032** | **2034** | **2036** | **2038** | **2040** | **2042** | **2044** | **2046** | **2048** | **2050** |
| **2.5** | 1 | 1 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| **5** | 1 | 1 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| **10** | 1 | 1 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| **20** | 1 | 1 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| **50** | 2 | 2 | 2 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| **100** | 2 | 2 | 2 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| **250** | 3 | 3 | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| **500** | 3 | 3 | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| **750** | 3 | 3 | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| **1000** | 3 | 3 | 3 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| **1500** | 4 | 4 | 4 | 4 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |

### Future Planned Work

NREL has performed substantial work, grounded in both empirical data and experienced engineering judgment, to develop the default assumptions for power curves and power curve transitions. Nonetheless, to ensure our full confidence in them, we plan to submit these assumptions to review by a technical review committee.2.5 Load Growth (Technology Agnostic)

### Summary

Growth in the aggregate consumption of electricity (i.e., load growth) in the dGen model is implemented as population growth: individual household and business level consumption is kept constant, while total number of hosueholds and businesses increases over time. This approach is consistent with the SolarDS (and REEDS?) models, used in NREL analyses like SunShot, Wind Vision, etc.

Load growth is applied by market sector at a regional level (Census Divisions) using projections from EIA’s Annual Electricity Outlook (add ref). Users may select from AEO’s 2014 or 2015 projections, including five options for each:

1. No Load Growth After 2014
2. Low Growth Case
3. Reference Case
4. High Growth Case
5. 2x Growth Rate of Reference Case

All 10 load growth scenarios are shown in the figure below. In all cases, the selected option is applied as a scalar multiplier on the initial number of customers in the starting model year (2012). Only one option can be selected for each model run.

[ add figure? ]

### Default Settings (All Years)

The default setting used by the dGen model is the AEO 2015 Reference Case. This is the most up-to-date projection available from AEO, which is presented by EIA as “a business-as-usual trend estimate, given known technology and technological and demographic trends” (add reference, page iii of AEO2015 report). While these projections have significant uncertainty, they provide an objective, well-informed basis for estimating future load growth and are a standard input to other NREL models (e.g., REEdS, others?).

### Planned Future Work

We are highly confident in the empirical basis for the dGen load growth assumptions and do not plan on performing additional work to support this assumption.

## 2.6 Electricity Rates and Rate Escalations (Technology Agnostic)

### Summary

The cost of electricity in the dGen model can be evaluated using three different, location-specific estimates of current (2014) electricity rates:

1. Real-world tariffs based on the Utility Rate Database (URDB) (OpenEI 2014)
2. Annual average flat rates by county ($/kWh) from EIA 861 forms (EIA 2015a)
3. User-defined flat rate structures by state

These electricity rates are assumed to change over time according to the following rate escalation options:

1. AEO 2015 Reference Case (Constant after 2040)
2. AEO 2015 Reference Case (Projected after 2040)
3. AEO 2014 Reference Case (Constant after 2040)
4. AEO 2014 Reference Case (Projected after 2040)
5. No Change

All options are applied by sector on a regional (Census Division) basis.

Options 1 through 4 are based on EIA’s AEO Reference Case projections (add ref). These projections for rate escalations end in 2040; however, the dGen model considers rate escalations through 2075 to accommodate customers considering adoption in 2050 and evaluating future rate growth. To account for these later model years, NREL modified the AEO projections using two different methods. With the first method (“Constant after 2040”), we assume that the project rate escalation for the final forecast year (2040) holds constant through 2075. Therefore, rates continue to grow after 2040, but simply at a constant rate for each year thereafter. With the second method (“Projected after 2040”), we applied time-series modeling to project rate escalations from 2041 through 2075. This method tends to use short-term temporal trends to forecast future values, and therefore has significant uncertainty in later years. It also tends to cause compounding escalation of rates. The figure below compares AEO 2015 Constant and Projected rate escalations for a single Census Division.

[add figure]

### Default Settings (All Years)

The default setting for rates used by the model for all model years are the URDB real-world tariffs. These data most closely represent the actual electricity costs incurred by current electricity consumers in the US. Refer to Section 4.4 of the dGen Model Documentation (Sigrin et al. 2015) provides a detailed discussion of these data.

The default setting for rate escalations used by the dGen model is the AEO 2015 (Constant after 2040). Similarly to the load growth assumptions, this is an objective, well-informed basis for estimating future rate escalations in the US. Furthermore, compared to the AEO 2015 (Projected after 2040) rate escalations, these escalations are more conservative and, therefore, help to place lower bounds on customer adoption levels.

### Planned Future Work

We are confident that the default settings for both rates and rate escalations are based on a strong empirical basis, and therefore, do not plan to perform research to further support them.

## 2.7 Wind 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?

## 2.8 Maximum Market Share 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