Managerial Flexibility in Levelized Cost Measures: A Framework for Incorporating Uncertainty in Energy Investment Decisions

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Abstract

Many irreversible long-run capital investments entail opportunities for managers to respond flexibly to changes in the economic environment. However, common levelized cost measures used to guide decision-making, such as the levelized cost of electricity, implicitly assume that the values of random economic variables are known with certainty when investment decisions are made. This assumption implies, often incorrectly, that managerial flexibility carries zero value. This paper improves levelized cost measures by deriving an expansion that accounts for both uncertainties in relevant variables and the value of managerial flexibility in responding to them. This method is applied to quantify the value of flexibility in two example decision problems. In one, an operator of a natural gas electricity generation facility evaluates whether to invest in carbon capture capabilities. Another considers retirement decisions for U.S. nuclear plants. These examples illustrate that simplified cost metrics can inaccurately guide decision-making by inflating cost estimates relative to the proposed levelized cost measure that accounts for uncertainty and flexibility.

Keywords: Levelized cost, managerial flexibility, uncertainty, investment decision-making, operational decision-making

1 Introduction

Decision-making about irreversible long-run capital investments is an essential managerial duty in industries such as electricity generation. Such investments often entail opportunities to respond flexibly to a variety of economic signals by, for example, deferring or staging investment decisions and expanding or contracting the scale of assets. The value of this flexibility has been well-established in the corporate finance literature, in which it is generally captured by the value of "real options" (Dixit and Pindyck, 1994) embedded in the investment opportunity, but not in cost-based measures used to assess investment opportunities.

In certain industries, it is common to evaluate investment opportunities based on cost effectiveness rather than solely corporate finance metrics, such as the net present value (NPV). In these cases, the "levelized product cost" (LPC) metric advanced by Reichelstein and Rohlfing-Bastian (2015) provides decision-makers with a relevant cost measure. The LPC is the average unit price that a facility must earn over its entire output to break even. In the energy literature, the LPC concept has been applied as the levelized cost of electricity (LCOE), which is defined as *"the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors"* (MIT, 2007). Generally, an investment is deemed *cost-competitive* with respect to other facilities when it produces an output (e.g., electricity) at an LPC (e.g., LCOE) at most equal to the prevailing market price.

Since the LPC ensures that the facility would cover all expenses and provide an acceptable return to investors, the measure is conceptually consistent with guidance from corporate finance that investors pursue opportunities with an NPV at least equal to zero. When managerial flexibility exists, however, a wedge may exist between the guidance provided by the LPC and NPV analyses. This is because only the latter approach has well-established methods to include managerial flexibility.

The main contribution of this paper is the derivation of a cost measure, the expanded LPC, to guide long-run investment decision-making in the presence of managerial flexibility. This metric presents two chief benefits. First, the expanded LPC is an appropriate cost measure for firms in competitive markets in which managers can fully incorporate the value of capital and operational flexibility. While Reichelstein and Rohlfing-Bastian (2015) include price uncertainty and a specific type of operational flexibility, this work adds the most general set of uncertainties to the LPC metric. Second, the expanded LPC extends the agreement between corporate finance- and cost metric-driven investment recommendations. In doing so, it facilitates the use of LPC metrics in the presence of managerial flexibility. While expanded NPV metrics are widely used to guide managerial decision-making under uncertainty (Trigeorgis, 1996), the expanded LPC allows a supplemental analysis: the comparison of assets with different time horizons and capital intensities that nonetheless compete in the same output markets.

The expanded LPC can accommodate a range of uncertainties and can be applied to a variety of investment settings where the parameters characterizing decision variables are uncertain. When applied in the electricity context to calculate LCOE values, the expanded LPC can guide decision-making for electricity generating facilities. These applications are illustrated in this paper with two examples. The first example studies the decision to invest in carbon capture technology by an operator of a natural gas power plant, provided uncertain future timing and cost of CO_2 emission penalties. The second example considers retirement decisions for the U.S. nuclear fleet, provided uncertainty about future costs and revenues alongside currently low electricity prices.

2 Literature Review and Related Work

This work ties three literature threads: (i) real options and managerial flexibility, (ii) planning under uncertainty, and (iii) investment decision measures. This section provides a selective survey of recent theoretical advances and applications related to the contributions of this paper.

2.1 Real Options and Managerial Flexibility

The concept and analysis of real options is the explicit consideration and inclusion of uncertainty in economic analysis. Real options analysis combines multiple scenarios built upon one or many relevant uncertain parameters into one economic evaluation (Seifert et al., 2015). While real options is the domain of evaluation, managerial flexibility provides necessary context, as it considers the value of control on an outcome. Managerial flexibility is the ability of asset- or project management to respond to the resolution of relevant (often market) uncertainty (Trigeorgis, 1996; Saleh, Mark, and Jordan, 2009). Such instances of control include the ability for a manager to determine (i) investment timing, (ii) asset abandonment, (iii) asset contraction/expansion, and (iv) operational switching/idling (Trigeorgis, 1993). The exploration of managerial flexibility within a real options framework has been extensively covered in the literature. For capital investment flexibility ((i) – (iii) above), key examples across industries include: sequential investment in chemical reactor assets (Seifert et al., 2015), IT asset purchases (Kauffman, Liu, and Ma, 2015), nuclear reactor investments (Cardin, Zhang, and Nuttall, 2017), wind farm investments (Diaz, Gomez-Aleixandre, and Coto, 2015), solar farm investments (Cheng et al., 2017), and carbon capture equipment attached to coal generation (Wang and Du, 2016). Other studies have examined both capital and operational flexibility ((i) - (iv) above), including for carbon capture and its operation (Mo et al., 2015), new product design (Kettunen et al., 2015), and even managerial performance indicators (Baldenius, Nezlobin, and Vaysman, 2016). Notably, while various economic and/or decision measures are used in the studies mentioned, the authors are not aware of any that have utilized a levelized product cost measure.

2.2 Planning Under Uncertainty

A key element of real options analysis is the assessment of parameter uncertainty to guide decision-making. Here, extensive research has been conducted within the domains of decision analysis and operations research (for an overview, see Ragozzino, Reuer, and Trigeorgis (2016)). Naturally, such representations of uncertainties are used as part of optimization studies. For example, Dong et al. (2013) build robust bounds on parameters, focusing on developing an approach to ensure system constraints are adhered given multiple, interacting uncertainties. Majewski et al. (2017) employ another approach of a mixed-integer linear program with multi-objective (bi-objective) optimization. The works of Vallerio et al. (2015) and Charitopoulos and Dua (2017) provide more comprehensive approaches of enumerating uncertainties in the context of multi-objective decision making. Within the energy context, decision-making under uncertainty has a long history in large-scale energy modeling with early stochastic programming examples like Dapkus and Bowe (1984). The energy modeling history of incorporating uncertainty into long-range planning is surveyed in Bistline (2015) and Wallace and Fleten (2003). However, even in this context, such assessment of parameter uncertainty has not been linked to managerial flexibility represented by levelized metrics.

While methods of resolution for such uncertainties are not explicitly discussed in this work, the proposed method is compatible with a variety of uncertainty assessment and quantification techniques (e.g., statistical methods, expert elicitation, etc.). Furthermore, the levelized cost framework developed here is agnostic toward the decision analytic framework used to evaluate strategies under uncertainty, allowing decision-makers and modelers to select a framework that is best suited for a particular application. The expanded LPC can be applied in tandem with deterministic and stochastic models, similar to the example in Section 6 where the LPC is linked with outputs from an energy-economic model.

2.3 Investment Decision Measures

By enabling a cost-based comparison of assets, the LPC informs investment decision-making and serves as an investment decision measure. Previous research has explored the impact of uncertainty on LPC measures, especially the LCOE, by explicitly including the uncertainty of key model parameters. Examples of notable work include Geissmann (2017), Heck, Smith, and Hittinger (2016), and Schachter and Mancarella (2016). However, in these cases and the broader LPC literature, while the uncertainty is explicitly modeled, the value and implications for the LPC of managerial flexibility are not. For example, to account for uncertainty, Darling et al. (2011) derive a distribution of LCOE measures from input parameter distributions feeding a Monte Carlo simulation. However, the LCOE derived from the expectation of underlying parameter values is not generally equal to the expected LCOE derived from distributions on underlying parameter values. The present work addresses the gap in the literature of incorporating the value of managerial flexibility in levelized product cost metrics to guide decision-making under uncertainty.

3 Managerial Flexibility, Uncertainty, and Investment Decision Measures

This section defines uncertainty and managerial flexibility and uses a conventional net present value approach to build intuition for the changes in cash flows that must be reflected in the expanded LPC (Section 4.2). The subsequent discussion assumes a competitive market setting and that all firms are risk-neutral with access to capital.

Figure 1 introduces the concepts of uncertainty and flexibility. Traditional investment decision measures occupy Quadrants 1 and 3 of Figure 1. If economic variables evolve stochastically and the manager cannot respond flexibly, metrics must be updated to provide measures in expectation, as in the *stochastic, passive* NPV measure in Equation 1. This equation occupies Quadrant 2 of Figure 1. Through the distribution $h(\omega)$, the stochastic, passive NPV measure reflects the probabilities that particular states of the world, ω, are realized.

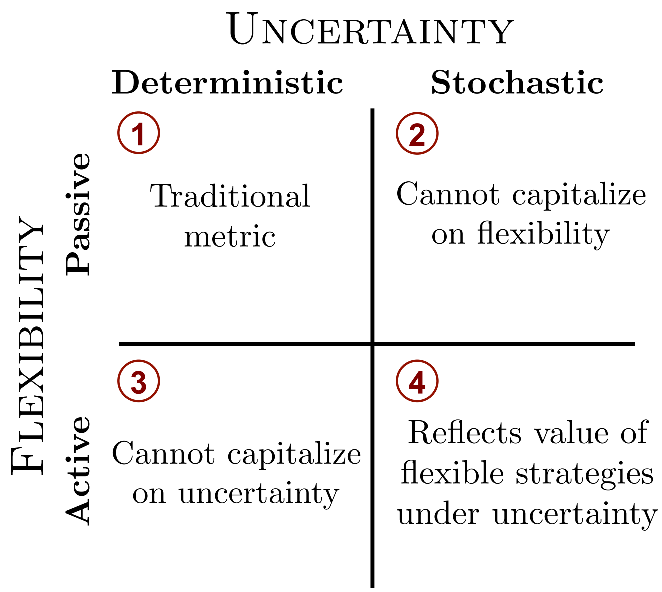

Figure 1: Taxonomy of investment decision measures, given treatment of uncertainty and flexibility.

$$\mathbb{E}[NPV] = \sum_{\omega \in \Omega} h(\omega) \cdot NPV_{\omega} \tag{1}$$

On the other hand, if the manager can change strategy as economic variables evolve, one must account for both uncertainty and changes in cash flows. Equation 2 expresses the updated measure. While this measure remains an NPV in expectation, it additionally reflects the value of strategic flexibility. This measure is called the *stochastic, expanded* NPV metric. Equation 2 presents the stochastic, expanded NPV, which occupies Quadrant 4 of Figure 1:

$$\mathbb{E}[NPV] = \left[\sum_{\omega \in \Omega} h(\omega) \cdot NPV_{\omega} \right] + \Phi \tag{2}$$

The stochastic, expanded NPV is the sum of the stochastic, passive NPV (first term on the right) and the option premium (second term on the right), which captures the value of flexible responses. The Φ term captures the incremental value from changes in the capital or operational profile that the manager makes as the economic environment evolves. This represents the value of all associated changes in operating costs, capital investment requirements, and revenues, including any changes in output that may occur in each state of the world. As with the other terms in Equation 2, Φ is defined in expectation over states of the world.

3.1 Conceptual Example

A conceptual example helps build intuition for the origin and nature of the cash flows entailed in Φ. Figure 2 illustrates two types of managerial flexibility, namely, capital and operational. The simplified two-stage diagram represents a decision context in which managerial flexibility includes first-stage capital flexibility (at time τ_1), then second-stage operational flexibility if adjustable capital is installed (at time τ_2). *Capital flexibility* refers to an embedded real option in which a manager can make capital budgeting decisions (e.g., adjust facility capacity) in response to realized or anticipated events. *Operational flexibility* allows asset owners to switch between operating modes in reaction to, or in anticipation of, events that can change expected cash flows. In the example context, the presence of operational flexibility is contingent on the exercise of operational flexibility in the first stage. For both types of managerial flexibility, the manager is assumed to enumerate potential discrete outcomes, quantify associated probabilities, and make decisions over time in response to available information.

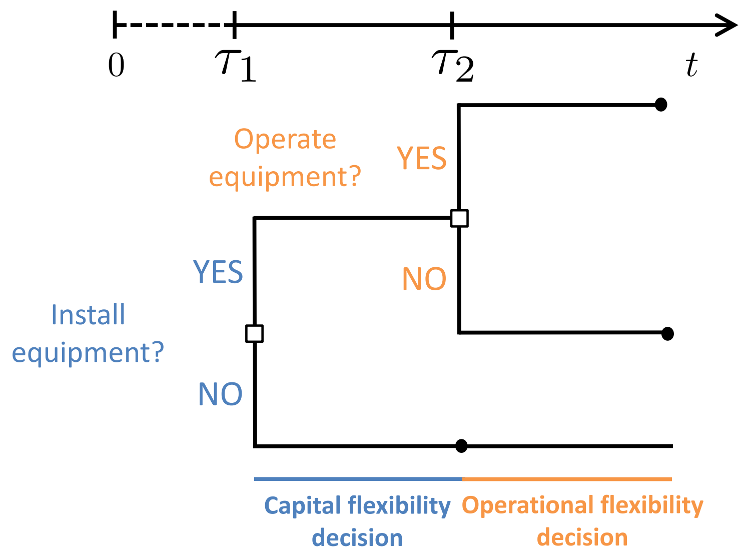

Figure 2: Illustrative scenario tree for managerial flexibility problem with capital and operational optionality.

3.1.1 Capital Flexibility

Facility owners may adjust asset capacity, or add or remove components of the productive asset in response to circumstances that materially affect operation, economic viability, or both. This capital flexibility is one type of real option often embedded in capital budgeting contexts. The firm's decision to exercise the option depends on factors such as irreversible investment outlay and expected volatility in the performance of the associated asset.

To illustrate the change in cash flows from capital flexibility, this section provides a simple example of an option with binary uncertain outcomes. Scenario 1 is a high-value state of the world for a firm's incumbent asset, and Scenario 2, a low-value state. The following parameters are introduced to guide extensions to the NPV:

SP_0	initial outlay to build capacity at $t = 0$; product of system price and capacity
V_H	future value of cash flows under Scenario 1
V_L	future value of cash flows under Scenario 2

The passive NPV (see Figure 1, Quadrant 2), can be expressed as the difference between the present value of the post-investment cash flows (represented by the random variable $\widetilde{V}$)

and the initial capital investment:

$$\mathbb{E}[NPV] = \mathbb{E}\left[\widetilde{V}\right] - SP_0 = \mathbb{E}\left[\sum_{t=1}^{T} CFL_t \cdot \kappa^t\right] - SP_0 \tag{3}$$

CFL_t denotes the cash flows at time t. The expression in (3) is evaluated in expectation, using $h(\omega)$, since the cash flows depend on the prevailing state of the world. One can quantify $h(\omega)$ by using characteristics of a twin security, as shown in Trigeorgis (1996). The twin security is an instrument traded in financial markets with the same risk characteristics as the real project under consideration (Trigeorgis, 1996). $h(\omega)$ reflects risk-adjusted probabilities with which states of the world obtain. Note that Equation 3 uses the discount factor κ, where $\kappa = \frac{1}{1+r}$, and r is the risk-free rate. The risk-free rate is justified because the distribution h already reflects the risks stemming from the stochastic processes affecting both the twin security and the investment under consideration. Defining the probabilities q and $1-q$ as specific instances of $h(\omega)$ in the two-scenario case, the estimation of their values uses the following terms:

q	probability of occurrence of Scenario 1 (high-value)
$1-q$	probability of occurrence of Scenario 2 (low-value)
Z	price of twin security traded in financial markets
k	expected return of twin security

The probability q is defined as:

$$q = \frac{(1+r)Z - Z_H}{Z_L - Z_H} \tag{4}$$

Above, Z_H is the high value of the twin security in Scenario 1, and Z_L is the low value of the twin security in Scenario 2. Re-expressing Equation 3:

$$\mathbb{E}[NPV] = q \cdot \left[\sum_{t=1}^{T} CFL_t(V_H) \cdot \kappa^t\right] + (1-q) \cdot \left[\sum_{t=1}^{T} CFL_t(V_L) \cdot \kappa^t\right] - SP_0 \tag{5}$$

The expressions that follow distinguish between decision stages (indexed by $s \in \mathcal{S}$) and time periods (indexed by $t \in \mathcal{T}$). Periods are intervals in the time horizon, and stages are sets of consecutive periods that divide the time horizon based on the ability of decision-makers to revise strategies given new information. The function $u \colon \mathcal{S} \to \mathcal{T}$ links consecutively numbered decision stages to time periods. In general, $\mathcal{S} \neq \mathcal{T}$, but these sets could be identical, which gives $u(s) = s$.

Assume that an option exists to install capital equipment on a facility at time τ_1, as illustrated in Figure 3. Upon exercising the option, the firm will bear new capital costs, with an equipment outlay SP_{τ_1} at τ_1 for an expanded facility that will be available immediately.

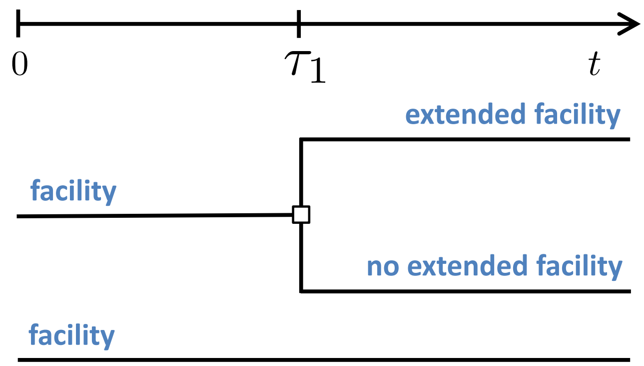

Figure 3: Timeline of the firm's growth option for investing in new capital equipment at time τ_1.

In general, after the investment (i.e., after τ_1), the fixed and variable costs, capacity, and availability (i.e., capacity factor) of the asset may change. Let $\xi^c_{t,\omega}$ represent the cumulative change in non-investment cash flows in each time period, with c denoting capital flexibility. $\xi^c_{t,\omega}$ includes all changes in fixed and variable costs and adjustments to revenues, given changes in overall facility availability and capacity entailed in exercising capital flexibility; these components will be further defined in Section 4. The index ω on $\xi^c_{t,\omega}$ allows for different cash flows per each state of the world. Further, let the random variable $\widetilde{E}$ denote the value of post-initial capacity investment cash flows in the case of managerial flexibility. Since these cash flows are at least equal to those implied by $\widetilde{V}$, $\widetilde{E}$ is represented as $\widetilde{E} = \max[\widetilde{V}, \widetilde{V} + (\sum_{t=\tau_1}^{T} \mathbb{E}[\xi^c_{t,\omega}] \cdot \kappa^{t-\tau_1} - SP_{\tau_1}) \cdot \kappa^{\tau_1}] = \widetilde{V} + \max[0, (\sum_{t=\tau_1}^{T} \mathbb{E}[\xi^c_{t,\omega}] \cdot \kappa^{t-\tau_1} - SP_{\tau_1}) \cdot \kappa^{\tau_1}]$. Without loss of generality, the assumption is that market conditions are favorable for capital deployment only in Scenario 2 (i.e., to ameliorate this low-value scenario). Thus, if Scenario 1 occurs, the firm will not invest in new capacity and will have a gross project value of $E_H = V_H$. Alternatively, if Scenario 2 occurs, management will install the equipment and have a gross project value of $E_L = V_L + (\sum_{t=\tau_1}^{T} \xi_t^c \cdot \kappa^{t-\tau_1} - SP_{\tau_1}) \cdot \kappa^{\tau_1}$.

From Equation (3), the value of the investment opportunity including the expansion option becomes:

$$\mathbb{E}[NPV] = \mathbb{E}\left[\sum_{t=1}^{T} CFL_t \cdot \kappa^t\right] - SP_0 = \mathbb{E}\left[\widetilde{E}\right] - SP_0 \tag{6}$$

This equation gives the general expression for the stochastic, expanded NPV (see Quadrant 4 of Figure 1). In the two-scenario example, this equation is expressed as:

$$\mathbb{E}[NPV] = q \cdot V_H + (1-q) \cdot \left[V_L + \left(\sum_{t=\tau_1}^{T} \xi_{t,L}^c \cdot \kappa^{t-\tau_1} - SP_{\tau_1}\right) \cdot \kappa^{\tau_1}\right] - SP_0 \tag{7}$$

The value of the option is called the option premium for capital flexibility (Φ^c) and represents the difference between the expanded and passive NPV measures. In the two-scenario example, Φ^c assumes the value:

$$\Phi^c = (1-q) \cdot \left(\sum_{t=\tau_1}^{T} \xi_{t,L}^c \cdot \kappa^{t-\tau_1} - SP_{\tau_1}\right) \cdot \kappa^{\tau_1} \tag{8}$$

In the general, multiple-scenario setting, the expression for the option premium in the stochastic, expanded NPV from Equation (2) is:

$$\Phi^c = \sum_{\omega \in \Omega} h(\omega) \cdot \left(\sum_{t=\tau_1}^{T} \xi_{t,\omega}^c \cdot \kappa^{t-\tau_1} - SP_{\tau_1}\right) \cdot \kappa^{\tau_1} = \mathbb{E}\left(\sum_{t=\tau_1}^{T} \xi_{t,\omega}^c \cdot \kappa^{t-\tau_1} - SP_{\tau_1}\right) \cdot \kappa^{\tau_1} \tag{9}$$

The expression above is appropriate in contexts where the investment opportunity entails only one capital investment stage subsequent to the initial investment period. The expression can be extended to account for scenarios in which the investment opportunity entails multiple investment stages.

3.1.2 Operational Flexibility

Operational flexibility allows the manager to switch between operating modes in reaction to, or in anticipation of, events that may alter expected cash flows. To illustrate the potential value of operational flexibility, consider a case in which the manager can choose between only two operational modes. Figure 2 depicts this setting. Imagine that after having installed new capital equipment, the manager is evaluating whether to operate such equipment. Three technologies that allow the equipment to operate in one of two modes are defined:

- F = The equipment can switch between "on" and "off" modes
- A = The equipment must operate in the "on" mode only
- B = The equipment must operate in the "off" mode only

This simplified example includes only one decision stage (i.e., at time τ_2), but it can be extended to any number of decision stages.

Assume that switching between modes of operation with flexible technology F is costless. Since the operator can alter the operational mode, the present value of the flexible technology (PV_F) is greater than the present value of either of the two inflexible technologies (PV_A and PV_B). Specifically, PV_F exceeds PV_A by the value of being able to switch from the "on" mode enabled by technology A to the "off" mode entailed by technology B. This value is represented by $F(A \to B)$. Since $F(A \to B)$ depends on an uncertain underlying economic variable, the value of the flexible technology is a random variable, $\widetilde{M}$. $\widetilde{M}$ is evaluated as follows:

$$\mathbb{E}\left[\widetilde{M}\right] = PV_A + F(A \to B) = \mathbb{E}\left[\sum_{t=\tau_1}^{T} CFL_t \cdot \kappa^t\right] + F(A \to B) \tag{10}$$

The time bounds reflect the timing of the capital investment at τ_1. The value of the flexible technology in each state of the world derives from the incremental cash flows implied by using technology F (which allows switching between modes) instead of technology A.

Let $\xi^o_{t,\omega}$ represent the cumulative change in non-investment cash flows in each time period, with o denoting operational flexibility. $\xi^o_{t,\omega}$ includes all changes in fixed and variable costs and adjustments to revenues, given changes in overall facility availability entailed in using technology F. These incremental cash flows occur in all time periods between that of stage two, τ_2, and the end of life for the facility, T). The value of the flexible technology can be expressed as:

$$\mathbb{E}\left[\widetilde{M}\right] = \mathbb{E}\left[\sum_{t=\tau_1}^{T} CFL_t \cdot \kappa^t\right] + F(A \to B) = \mathbb{E}\left[\sum_{t=\tau_1}^{T} CFL_t \cdot \kappa^t\right] + \mathbb{E}\left[\sum_{t=\tau_2}^{T} \xi^o_{t,\omega} \cdot \kappa^t\right] \tag{11}$$

Both expectation terms of (11) are assessed over all scenarios, ω, using the risk-adjusted probability measure, $h(\omega)$.

Equation (11) implies the value of operational flexibility in the context of one operational decision stage and two operational modes:

$$\Phi^o = F(A \rightarrow B) = \mathbb{E}\left[\sum_{t=\tau_2}^{T} \xi^o_{t,\omega} \cdot \kappa^t\right] \tag{12}$$

The value of operational flexibility is affected by the number of decision stages and duration over which it would be optimal to exercise this flexibility. As the number of decision stages increases *ceteris paribus*, the value of operational flexibility increases. It is advantageous to match decision stage frequency with the timescale of the underlying stochastic variable. Since $\xi^o_{t,\omega}$ account for the cumulative change in non-investment cash flows in each time period, the right side of Equation (11) applies more generally to contexts with a greater number of decision stages. The equation is tailored to the example in accounting for changes in cash flows only after τ_2.

In general, the manager may be able to use a technology X that permits switching from a default mode to one of n alternative modes. In this more general context, the value of operational flexibility can be isolated in exactly the same manner, namely, by accounting for all incremental cash flows relative to a less flexible technology. Equation (12) defines the option premium in the expanded NPV from Equation (2) for decision contexts where operational flexibility is present. Passive NPV calculations that neglect these sources of managerial flexibility may be omitting critical decision-relevant dynamics.

3.2 Combined Managerial Flexibility

The previous two subsections have added independent capital and operational flexibility considerations to the LPC. In general, managerial flexibility is the combination of capital and operational flexibility, where the representation of these post-flexibility cashflows is represented as $\xi_{t,\omega}$. Yet, the value of this combination is not immediately obvious. The value of an option in the presence of other options may differ from its value in isolation (Trigeorgis, 1993).

$$\Phi \lesseqgtr \Phi^o + \Phi^c \tag{13}$$

Interactions between options depend on the type, temporal separation, extent to which options are "in or out of the money," and order of the options involved. All of these factors impact the joint probability of exercising these options (Trigeorgis, 1993).

4 Incorporating Uncertainty and Managerial Flexibility in the LPC

The LPC measure must account for the passive cash flows entailed in the incumbent asset as well as the post-flexibility cash flows, which were introduced as $\xi_{t,\omega}$ in the previous section. This section first introduces the base LPC decision measure. It subsequently outlines the stochastic, passive measure and derives the stochastic, expanded measure.

4.1 The Base Measure

To estimate the LPC, the manager apportions capital costs across all units of output and, upon combining these with ongoing fixed and variable costs, arrives at a full cost estimate to inform the investment decision. The LPC is defined by:

$$LPC = w + f + c \tag{14}$$

where w captures time-averaged variable operating costs, f represents fixed operating costs, and c is the cost of capacity. In general, levelized product cost metrics include terms to characterize tax-, depreciation- and debt-related cash flows. To focus on the needed updates to account for uncertainty and flexibility, the expressions below do not include these terms. The extension to do so would straightforwardly follow the approach in Reichelstein and Yorston (2013). Constant returns-to-scale technologies are assumed for w, meaning that these values are constant in each period up to the maximum capacity of the facility (Reichelstein and Yorston, 2013; Reichelstein and Rohlfing-Bastian, 2015). Equations (15) and (16) introduce w and f formally:

$$w = \frac{\sum_{t=1}^{T} W_t \cdot a \cdot x_t \cdot \gamma^t}{m \sum_{t=1}^{T} CF_t \cdot a \cdot x_t \cdot \gamma^t} \tag{15}$$

$$f = \frac{\sum_{t=1}^{T} F_t \cdot \gamma^t}{m \sum_{t=1}^{T} CF_t \cdot a \cdot x_t \cdot \gamma^t} \tag{16}$$

Respectively, W_t and F_t reflect the allocation of ongoing variable and fixed operating costs (in dollars) across all output. The term γ is equal to $\frac{1}{1+d}$, where d is the cost of capital and is taken as exogenous. In the case in which the project retains the firm's leverage ratio and matches the risk characteristics of the firm, the appropriate discount rate is the weighted average cost of capital. T represents the operational life of the facility in years. Finally, where output is measured on the basis of production per unit time (rather than on a unit product basis), m represents hours in the year. For example $m = 8,760$ in the case of electricity production, to arrive at an LPC expressed in dollars per kilowatt hours ($\$/MWh$).

The capacity factor CF_t reflects the ratio of actual output to its full nameplate capacity. The capacity factor term differs from the system degradation factor term, x_t, in that the latter reflects physical characteristics of a unit. For example, expected changes in process yield would be described by x_t, which adjusts the volume of output anticipated in any period t. x_t represents the decay in the ability of a system to produce its output and usually takes the form of a constant percentage factor, which varies with the particular technology (Reichelstein and Yorston, 2013). In contrast, CF_t can change over time due to factors like the unit's position on the supply curve, a changing grid composition (i.e., as capacity is added or retired), and other market characteristics. The term a refers to the physical capacity of the facility, which is independent of CF_t. The physical capacity, in the absence of any subsequent managerial decision, is typically fixed at the magnitude of initial build. Quantity produced in any period t is the product of capacity factor, capacity of the facility, and degradation factor (i.e., $CF_t \cdot a \cdot x_t$). When output is measured on the basis of production per unit time, this term is scaled by m.

The third term of Equation (14) levelizes upfront capital costs of the amount SP (system price in dollars) over all output from the productive asset. This levelization follows the approaches by Arrow (1964) and Rogerson (2008) and is known as the unit cost of capacity:

$$c = \frac{SP}{m \sum_{t=1}^{T} CF_t \cdot a \cdot x_t \cdot \gamma^t} \tag{17}$$

Consistent with the qualitative definition of the LPC as the price required to cover project costs, an investment would be cost competitive if $LPC = w + f + c \leq p$, where p is the prevailing market price for the asset's output. The base LPC and its application to cost-competitiveness applies to Quadrant 1 of Figure 1. In Quadrant 3, since price may change in each state of the world, the cost-competitiveness criterion changes to $LPC = w+f+c \leq \mathbb{E}[p]$, where the expectation term is over the states of the world, ω.

4.2 Incorporating Uncertainty and Managerial Flexibility in the LPC

4.2.1 Adding Uncertainty to the LPC

The base LPC measure can be readily extended to account for uncertainty alone. In Equations (15), (16), and (17), each of the key cost measures (namely, W_t, F_t, and SP) is updated to $W_{t,\omega}$, $F_{t,\omega}$, and SP_ω to account for uncertainty. Using $h(\omega)$ to define cost components in expectation, the discounting terms in Equations (15), (16), and (17) are switched from γ^t to κ^t, as $h(\omega)$ already accounts for the risk that would otherwise be reflected in the weighted cost of capital used to derive γ^t.

Taking expectations over ω, the stochastic, passive LPC that applies to Quadrant 2 of Figure 1 is:

$$\mathbb{E}[LPC] = \sum_{\omega \in \Omega} h(\omega) \cdot (w_\omega + f_\omega + c_\omega) \tag{18}$$

Proposition 1 below summarizes cost competitiveness criteria in the presence of uncertainty. Appendix A presents a proof.

Proposition 1 *The stochastic, passive LPC is given by Equation (18) and is the appropriate cost measure for long-term decision-making when the economic environment is characterized by uncertainty. The asset is cost competitive if and only if* $\mathbb{E}_\omega[p] \geq \mathbb{E}_\omega[w + f + c]$.

4.2.2 Adding Managerial Flexibility to the LPC

As Section 3.1 demonstrated, the exercise of managerial flexibility generally introduces changes in three components: (i) changes in (capital) investment requirements, (ii) changes in operating costs, and (iii) changes in output. The optionality premium terms derived in that section reflect the error in the passive LPC metrics when flexibilty is possible. This section derives the necessary updates to account for both uncertainty and managerial flexibility in the LPC.

General changes in capital investment requirements are summarized by:

$$\sum_{\omega} h(\omega) \cdot SP_{\omega} \cdot \kappa^{\tau_{\omega}}$$

Where, without loss of generality, τ_{ω} denotes the time period in which investment needs are summarized. In the two-scenario example provided in Section 3.1, τ_{ω} is τ_1. Changes in operating costs and output, which were previously summarized as $\xi^c_{t,\omega}$ and $\xi^o_{t,\omega}$, are incorporated using the following terms:

$dW_{t,\omega}$	cumulative changes in variable costs relative to incumbent
$dF_{t,\omega}$	cumulative changes in fixed costs relative to incumbent
$dCF_{t,\omega}$	cumulative changes in facility capacity factor relative to incumbent
$da_{t,\omega}$	cumulative changes in facility capacity relative to incumbent

Amending expressions from Reichelstein and Yorston (2013), the subsequent expression summarizes the requirement for the investor to at least break-even in the presence of uncertainty:

$$\sum_{\omega} h(\omega) \left[\left[\sum_{t=1}^{T} m \cdot x_t \cdot a \cdot CF_t \cdot (p_{\omega} - W_{t,\omega}) - F_{t,\omega} \right] \cdot \kappa^t - SP_{o,\omega} \right] \geq 0$$

Substituting the components that express changes in operating costs, capacity factor, and capacity into the preceding to account for managerial flexibility results in:

$$\sum_{\omega} h(\omega) \left[\sum_{t=1}^{T} \left[m \cdot x_t \cdot [a - da_{t,\omega}] \cdot [CF - dCF_{t,\omega}] \cdot (p_{\omega} - W_{t,\omega} - dW_{t,\omega}) - [F_t - dF_{t,\omega}] \right] \cdot \kappa^t - SP_{o,\omega} - SP_{\omega} \cdot \kappa^{\tau_{\omega}} \right] \geq 0 \tag{19}$$

In order to time-average the costs included in Equation (19), the expanded expression above is divided by the output of the incumbent, which is:

$$\sum_{t=1}^{T} m \cdot x_t \cdot a \cdot CF_t \cdot \kappa^t$$

The resulting quotient follows:

$$\sum_{\omega} h(\omega)\left[(p_\omega)\cdot\left[1-\frac{\sum_{t=1}^{T} x_t\cdot\kappa^t\cdot\lambda_{t,\omega}}{\sum_{t=1}^{T} x_t\cdot a\cdot CF_t\cdot\kappa^t}\right]-(w_\omega)\cdot\left[1-\frac{\sum_{t=1}^{T} W_{t,\omega}\cdot x_t\cdot\kappa^t\cdot\lambda_{t,\omega}}{\sum_{t=1}^{T} x_t\cdot a\cdot CF_t\cdot\kappa^t}\right]\right.$$
$$\left.-(dw_\omega)\cdot\left[1-\frac{\sum_{t=1}^{T} dW_{t,\omega}\cdot x_t\cdot\kappa^t\cdot\lambda_{t,\omega}}{\sum_{t=1}^{T} x_t\cdot a\cdot CF_t\cdot\kappa^t}\right]-f_\omega-df_\omega-c_\omega-c_\omega^c\cdot\kappa^{\tau,\omega}\right]\geq 0 \tag{20}$$

Equation (20) introduces four new terms as defined and interpreted below. The first term, $\lambda_{t,\omega}$, is the cumulative change in output at the given time and is defined as:

$$\lambda_{t,\omega}=dCF_{t,\omega}\cdot a-CF_t\cdot da_t-dCF_{t,\omega}\cdot da_{t,\omega}$$

The second and third terms, df_ω and dw_ω, are the incremental changes in variable and fixed costs, aggregated over all preceding time and levelized over the output of the passive investment. They are defined respectively as:

$$dw_\omega=\frac{\sum\limits_{t=1}^{T} dW_{t,\omega}\cdot a\cdot x_t\cdot\kappa^t}{m\sum\limits_{t=1}^{T} CF_t\cdot a\cdot x_t\cdot\kappa^t}$$

$$df_\omega=\frac{\sum\limits_{t=1}^{T} dF_{t,\omega}\cdot\kappa^t}{m\sum\limits_{t=1}^{T} CF_t\cdot a\cdot x_t\cdot\kappa^t}$$

Similarly, the fourth and final term c_ω^c is the incremental change in capital costs, levelized over the output of the passive investment, defined analogously as Equation (17).

Rearranging Equation (20) yields:

$$\sum_{\omega} h(\omega)\cdot(p_\omega)\cdot\left[1-\frac{\sum_{t=1}^{T} x_t\cdot\kappa^t\cdot\lambda_{t,\omega}}{\sum_{t=1}^{T} x_t\cdot a\cdot CF_t\cdot\kappa^t}\right]\geq\sum_{\omega} h(\omega)\left[w_\omega+f_\omega+c_\omega+dw_\omega+df_\omega+c_\omega^c\cdot\kappa^{\tau_\omega}\right.$$
$$\left.+\frac{\sum_{t=1}^{T} W_{t,\omega}\cdot x_t\cdot\kappa^t\cdot\lambda_{t,\omega}}{\sum_{t=1}^{T} x_t\cdot a\cdot CF_t\cdot\kappa^t}+\frac{\sum_{t=1}^{T} dW_{t,\omega}\cdot x_t\cdot\kappa^t\cdot\lambda_{t,\omega}}{\sum_{t=1}^{T} x_t\cdot a\cdot CF_t\cdot\kappa^t}\right] \tag{21}$$

The term to the right of p_ω is an adjustment factor to the expected price to account for changes in output. The adjustment factor, represented as Γ_ω, ensures fixed and capital costs are covered at the proper output quantity.

Let ϑ_ω represent the value of managerial flexibility captured in Equation (21). Then, it is defined as:

$$\vartheta_\omega = dw_\omega + df_\omega + c^c_\omega \cdot \kappa^{\tau_\omega} + \frac{\sum_{t=1}^{T} W_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} + \frac{\sum_{t=1}^{T} dW_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t}$$

A substitution of ϑ_ω for the appropriate terms of the right hand side of Equation (21) yields the stochastic, expanded LPC, as summarized by Equation (22) and Proposition 2:

$$\mathbb{E}_\omega[LPC] = \mathbb{E}_\omega[w_\omega + f_\omega + c_\omega + \vartheta_\omega] \tag{22}$$

Proposition 2 *The stochastic, expanded LPC is given by Equation (22) and is the appropriate cost measure for long-term decision-making when the economic environment is characterized by uncertainty and managerial flexibility.*

The stochastic, expanded LPC in Equation (22) applies to Quadrant 4 of 1. Additional details about the proof are presented in Appendix A. Proposition 2, together with Equation (21) and the definition of Γ_ω above, immediately imply the Remark below:

Remark 1 *A facility is cost competitive in expectation if and only if* $\mathbb{E}_\omega[p_\omega \Gamma_\omega] \geq \mathbb{E}_\omega[w_\omega + f_\omega + c_\omega + \vartheta_\omega]$.

Proposition 2 and the Remark above apply broadly to situations in which the firm faces uncertainty, regardless of whether it exercises managerial flexibility.

5 Illustration: Natural Gas Power Plant with Carbon Capture

Many jurisdictions are considering placing a cost on CO_2 emissions from fossil fuel electricity generation and obligating facility owners to absorb these costs. Both the timing and ultimate cost of such rules would have a material impact on the economic viability of coal and natural gas facilities. This example considers a natural gas power plant that may need to comply with policies penalizing CO_2 emissions (see Comello and Reichelstein (2014) for a complementary study). Although the nature of these policies is uncertain, this section assumes a policy that places a cost on each unit of CO_2 emitted. In response, the plant owner has the option to invest in carbon capture capabilities, which lowers CO_2 emissions. Applying carbon capture to a gas plant entails high capital and operational costs. Therefore, the LCOE for a facility with carbon capture is significantly higher than the same generator without such capability. This stems not only from higher costs but also a reduction in net output due to the energy requirement of the capture unit (i.e., parasitic losses).

Given uncertainty in carbon prices, this setting implies both capital and operational flexibility. If CO_2 emissions costs are low, an immediate investment in capture technology would be uneconomic. If carbon costs were to rise in the future, the manager could retrofit the plant with carbon capture capabilities, which provides capital flexibility. Moreover, the manager may want to turn off capture units, once installed, to avoid higher operational costs if carbon prices were to drop. This option provides operational flexibility.

Using the input values detailed in Appendix B, the LCOE of a natural gas fired power plant without carbon capture and facing no emissions penalties (i.e., the incumbent facility) is \$66/MWh. The Appendix also outlines the changes in investment and operational costs entailed in the installation of carbon capture facilities, namely, SP_{τ_1} = \$1.2M/MW, dw = \$2.4/MWh, and df = \$19k/MW-yr. Assuming a change in capacity of da = 86 MW, no change in capacity factor (i.e., $dCF = 0$), no change in electricity price, and a retrofit that adds capture capability immediately (i.e., in year 0), then the LCOE would be \$106/MWh (9% higher than if the total facility was originally constructed with capture capabilities from the start).

To illustrate the value of capital flexibility, a 50% probability of a low emissions cost (i.e., zero carbon price) and 50% probability of an *a priori* unknown high-cost emissions price are assumed. As shown in Figure 4, the option to install carbon capture becomes valuable provided a (probabilistic) sufficiently high cost of emissions. For example, if emissions costs rise to \$100/tCO_2 five years after the incumbent facility begins operation, its LCOE with capital flexibility (ability to install carbon capture facilities) is \$83/MWh compared to \$87/MWh without it. The \$4/MWh example value of capital flexibility (i.e., 5% below original passive LCOE calculation) exemplifies the potential of default levelized product cost metrics to inflate the costs of operating assets by ignoring managerial flexibility.

Next, to illustrate the value of operational flexibility, it is assumed that emissions costs

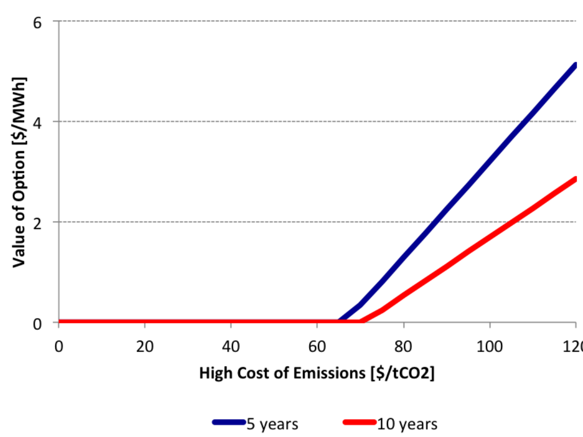

Figure 4: Value of capital flexibility

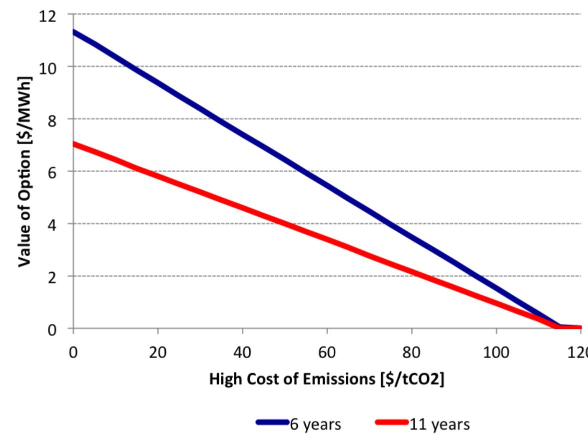

Figure 5: Value of operational flexibility

one year after capture unit installation are equal to zero or an *a priori* unknown high value with 50% probability. This scenario reflects a cap-and-trade emissions regime where the cost of emissions could vary stochastically. Provided capture units can be "switched off," Figure 5 represents the value of operational flexibility. Specifically, Figure 5 shows the value of the option to shut off the capture unit, should the cost of emissions fall below a threshold. In the case where capture units are switched off one year after they are installed in year 5 (the "6 years" line on the plot), it would be economically advantageous to do so if the stochastic high emissions cost falls below \$115/tCO_2. Given this timing, and if the emissions cost falls to \$50/tCO_2 for example, the LCOE with operational flexibility is \$83/MWh compared to \$89/MWh without it. Again, the \$6/MWh example value of operational flexibility (i.e., 7% below original passive LCOE calculation) highlights the potential of default levelized product cost metrics to inflate the costs of operating assets by ignoring managerial flexibility.

6 Illustration: Retirement Decisions for the U.S. Nuclear Fleet

Declining power prices and lack of compensation for environmental attributes have placed increasing financial stress on the U.S. nuclear fleet. Many units are at risk of premature retirements, and decisions by asset owners hinge not only on current profitability but also on expectations of uncertain future cost and revenue streams. This example considers retirement decisions for all existing U.S. nuclear plants in restructured markets given uncertainty about future natural gas prices and federal climate policy. Figure 6 illustrates the four possible states-of-the-world for this decision, which are initially assumed to have equal probabilities:

- **Reference natural gas prices, reference climate policies:** Reference natural gas prices come from the Energy Information Administration's 2017 Annual Energy Outlook. The reference policy scenario assumes all existing state and federal policies (e.g., state renewable mandates, regional climate policies, and federal tax incentives) but does not include any federal cap on CO_2 emissions.

- **Low natural gas prices, reference climate policies:** The lower natural gas price trajectory assumes NYMEX Henry Hub natural gas futures prices through 2030 and flat prices thereafter through 2050.

- **Reference natural gas prices, stringent emissions cap:** In addition to reference gas prices, this state of the world assumes aggregate U.S. electric sector CO_2 emissions caps consistent with the Clean Power Plan through 2030 and then linear reductions through 2050. In an economy-wide target of 80% reductions in greenhouse gas emissions relative to 2005 levels (consistent with Climate Action Plan goals), the 2050 cap of 95% in power sector greenhouse gas emissions relative to 2005 levels reflects the electric sector's lower abatement cost and role of electrification in reducing emissions in other sectors (Clarke et al., 2013).

- **Low natural gas prices, stringent emissions cap:** Per the assumptions as above.

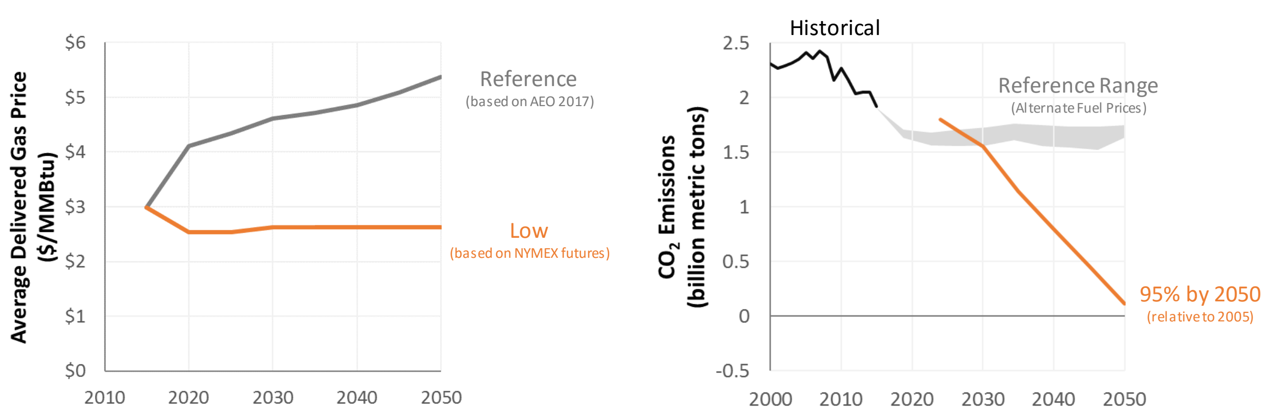

Figure 6: Natural gas price sensitivities (left) and electric sector emissions caps (right).

Capacity mixes across different states-of-the-world and the corresponding market prices come from EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model (EPRI, 2017). US-REGEN is a state-of-the-art, large-scale energy-economic model with detailed electric sector capacity planning and dispatch through 2050, which simultaneously optimizes investments (including new capacity, retrofits, and retirements), operational choices, and interregional transmission. The model has been applied in a wide range of power sector and energy contexts (Bistline, 2017; Bistline, Niemeyer, and Young, 2017; Rose and Bistline, 2016; James, Hesler, and Bistline, 2015; Blanford, Merrick, and Young, 2013). In addition to its detailed spatial resolution, the detailed intra-annual temporal resolution and regional heterogeneity are critical for accurately representing power system operations and trade, including the covariation of hourly load and renewable output. Technological cost and performance assumptions are discussed in EPRI (2017). Note that, unlike the model in the previous section, which is written in Excel and can be run on a standard laptop in seconds, each state of the world for this example is a separate run in US-REGEN. US-REGEN is written in GAMS, and each run takes approximately 30 minutes on an Intel Core i7-4960X (3.60 GHz) with 32 GB RAM. Regional electricity prices for the four scenarios are shown in Figure 9.

Figure 7 illustrates how net annual returns vary by plant across the four states-of-the-world. Net returns represent the difference between plant revenues like energy and capacity payments (Stoft, 2002) and costs like fuel, variable and fixed operations and maintenance, and capital expenditures. Figure 10 shows revenues and costs decomposed by category for a specific plant.

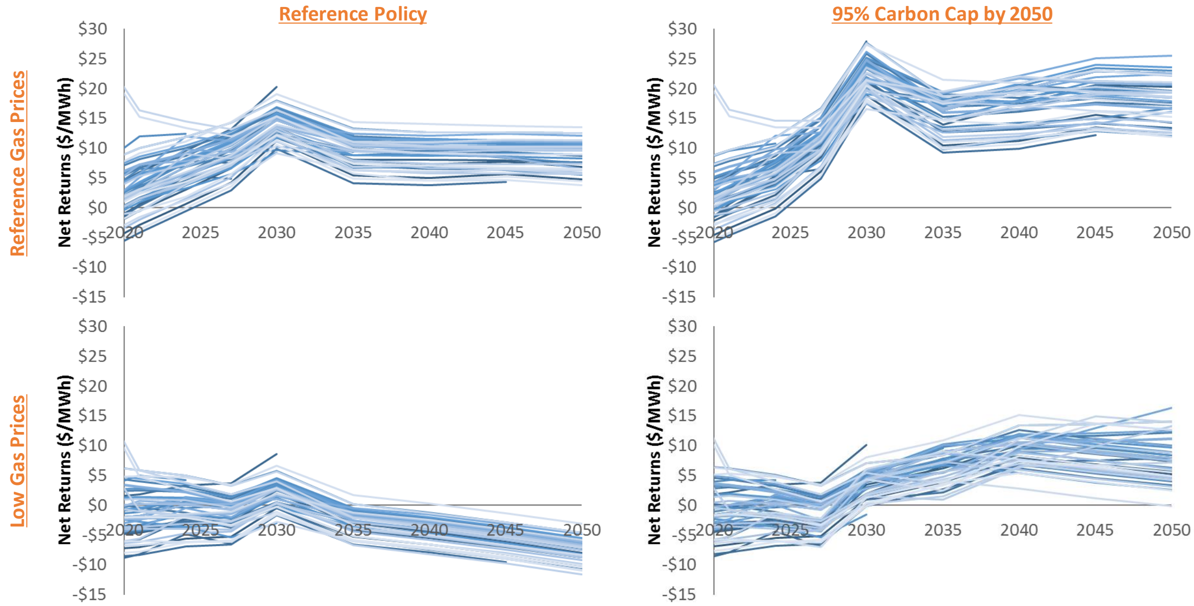

Figure 7: Net annual returns normalized by output ($ per MWh) for each nuclear plant over time by scenario, assuming hypothetical must-run dispatch.

Without retirements or option to mothball, many plants are currently unprofitable, but longer-run financial prospects vary considerably by plant and scenario. Lower gas prices depress wholesale power prices and exacerbate losses in competitive markets over time, which creates strong economic incentives for unit retirement. However, stringent climate policies like the 95% cap raises energy and capacity prices at the margin, helping to make many nuclear plants profitable, even in low gas price environments.

Given future uncertainty about natural gas prices and climate policy, there are two potential strategic options for the asset manager:

1. **Retirement option:** If future revenues do not exceed anticipated costs in expectation, then asset owners would prefer to retire the plant. The value of the option to retire is calculated by taking the probability-weighted difference between the must-run NPV (e.g., Figure 7) and the maximum of zero and this same must-run NPV across all states-of-the-world. If the retirement option is exercised, all fixed and variables costs drop to zero after the retirement date (during periods where the facility would otherwise be operating at a loss) along with the capacity factor and capacity.

2. **Mothballing option:** Retirement decisions for nuclear plants are currently irreversible, as a unit cannot return to service after its license has been surrendered.

However, the ability to restart a reactor would be valuable for plants whose longer-run financial prospects are more attractive than short-run margins suggest, especially if power prices rise over time due to higher gas prices or a carbon price. The value of the mothballing option is the probability-weighted difference between the NPV with the retirement option and non-negative present value in each period across all states of the world. Like the retirement option, the mothballing option entails zero-valued costs during otherwise unprofitably periods but, unlike retirement, does not necessarily maintain this state in perpetuity.

Figure 8 shows the levelized value of the retirement and mothballing options for each nuclear plant, which are probability-weighted across the four states of the world. The figure demonstrates the economic significance of both types of options, even though the magnitude depends on the probabilities associated with future states of the world. Although this figure aggregates information across scenarios, it demonstrates how the retirement option is generally higher for single-reactor plants, as these sites tend to have higher costs and more states-of-the-world where going-forward expected revenues would be lower than expected costs. Values to the far right include plants with announced retirements. Current levelized costs for nuclear plants range from roughly \$20–35/MWh, so ignoring optionality values approaching \$5/MWh could be significant omissions. In other words, the value of embedded options could be as high as 25% of the LCOE value without flexibility. Additionally, the mothballing option value is higher for multiple-reactor plants with their lower normalized costs leading to more conditions under which low near-term prices (but expectations of future escalations) would make such an option valuable to asset owners.

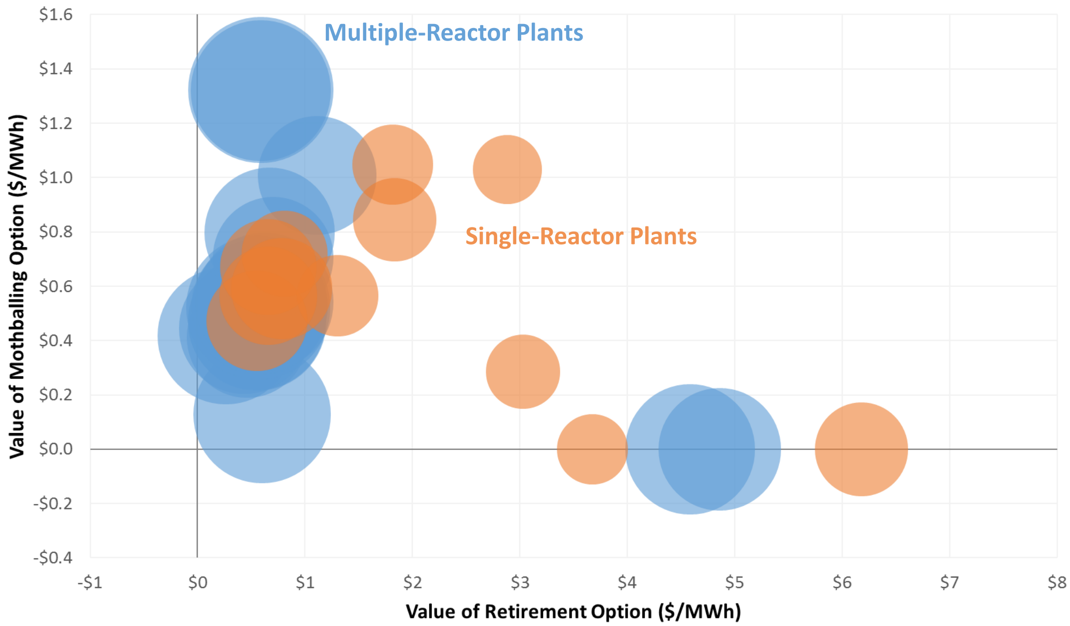

Figure 8: Value of retirement option (horizontal axis) and mothballing option (vertical axis) in for nuclear plants in competitive markets. Metrics are expressed in levelized ($ per MWh) terms. Orange points represent single-reactor plants, and blue points represent multi-reactor sites. The size of circles is proportional to maximum plant capacity.

7 Conclusion

Irreversible, long-run capital decision making under uncertainty is a core activity of management in industries such as electricity generation. Investment decision measures, such as the net present value and the levelized product cost, must accommodate the complexities of uncertainty and managerial flexibility. To date, measures based on levelized product cost metrics have not had a standard approach to assessing the value of "real options" embedded in capital assets and have tended to assign no value to managerial flexibility. The main contribution of this paper is the derivation of the expanded LPC, a cost measure to guide long-run investment decision-making in the presence of managerial flexibility. Unlike traditional LPC measures, the expanded LPC is an appropriate cost measure for firms in competitive markets in which managers can fully incorporate the value of managerial flexibility. Since the expanded LPC is derived from an explicit requirement that expected revenues exceed the expected costs of an asset, this work extends the agreement between the NPV and LPC metrics.

The expanded LPC explicitly introduces elements that represent changes in capital investment requirements, changes in operating costs and changes in output. With these changes, the measure can accommodate a range of uncertainties and can be applied to a variety of investment settings where the parameters characterizing decision variables are stochastic. The cumulative effect of the expanded measure is a set of additional terms that are added to the traditional, passive LPC. These terms represent "updates" to the cash flows of the incumbent asset and adjustments to legacy terms from the traditional, passive LPC that account for changes in output. In addition, to guide investment decisions, the analysis demonstrates that prices must be scaled by an adjustment factor that reflects changes in output, given the potential exercise of managerial flexibility.

The inaccuracy between expanded and passive LPC can be material, as demonstrated in the provided examples. In the example case of carbon capture technology paired with a natural gas generation facility, the otherwise neglected option value could represent approximately 5–7% of the no-flexibility LCOE value. Similarly, in the example case of nuclear fleet retirements, the value of embedded options could be as high as 25% of the no-flexibility LCOE value. Future work may apply the developed approach to a wider set of scenarios, including more complex operational decision settings with a greater number of underlying uncertainties. Such exercises ought to prove illuminating to both industry operators and policymakers alike.

A Proof of Propositions

Claim for Proposition 1: In the presence of uncertainty but *absence* of managerial flexibility, an asset is cost competitive if and only if:

$$\mathbb{E}_\omega[p] \geq \mathbb{E}_\omega[w + f + c] \tag{1}$$

We begin by verifying that the expression above represents the cost competitiveness requirement. Equation (2) summarizes requirements on cash flows in the presence of uncertainty but absence of managerial flexibility, i.e., no changes in operational or capital strategy. Note that this formulation assumes a capacity factor that remains unchanged in all states of the world.

$$\sum_\omega h(\omega) \left[\left[\sum_{t=1}^{T} m \cdot x_t \cdot a \cdot CF_t \cdot (p_\omega - W_{t,\omega}) - F_{t,\omega} \right] \cdot \kappa^t - SP_{o,\omega} \right] \geq 0 \tag{2}$$

Dividing both sides of Equation (2) by the output of the asset, i.e.:

$$\sum_{t=1}^{T} m \cdot x_t \cdot a \cdot CF_t \cdot \kappa^t \tag{3}$$

and simplifying using the definitions for $w_/omega$, $f_/omega$ and $c_/omega$ provided in Section 4.2.1, the result is:

$$\sum_\omega h(\omega)[p_\omega - w_\omega - f_\omega - c_\omega] \geq 0 \tag{4}$$

With trivial reformulation:

$$\sum_\omega h(\omega)[p_\omega] \geq \sum_\omega h(\omega)[w_\omega + f_\omega + c_\omega] \tag{5}$$

This leads to the target expression:

$$\mathbb{E}_\omega[p] \geq \mathbb{E}_\omega[w + f + c] \tag{6}$$

The opposite implication, i.e., that if $\mathbb{E}_\omega[p] \geq \mathbb{E}_\omega[w + f + c]$, the asset is cost competitive in expectation, follows trivially from the definition of the terms of the cost metric. ■

To verify the claim in Proposition 2 and accurately expand the expression from Proposition 1 to account for managerial flexibility, the expression in Proposition 2 would need to account for three sets of changes, namely (i) changes in (capital) investment requirements, (ii) changes in operating costs, and (iii) changes in output.

Changes in investment are introduced by the following term, where without loss of generality, it is assumed that cumulative investment requirements can be summarized by this single term:

$$\sum_{\omega} h(\omega) \cdot SP_{\omega} \cdot \kappa^{\tau_{\omega}}$$

Above, τ_{ω} denotes the time period in which investment needs are summarized.

Next, changes in operational costs are introduced by the items:

$$dW_{t,\omega}$$

$$dF_{t,\omega}$$

Finally, changes in output are introduced by the items:

$$dCF_{t,\omega}$$

$$da_{t,\omega}$$

The terms used to denote changes in operational costs and changes in output are defined as the cumulative change in the relevant measure *ex post* all strategic actions relative to the initial (i.e., no-flexibility) level.

Then, the following expression summarizes the requirement for the investor to at least break-even:

$$\sum_{\omega} h(\omega) \left[\sum_{t=1}^{T} \left[m \cdot x_t \cdot [a - da_{t,\omega}] \cdot [CF - dCF_{t,\omega}] \cdot (p_{\omega} - W_{t,\omega} - dW_{t,\omega}) - [F_t - dF_{t,\omega}] \right] \cdot \kappa^t - SP_{o,\omega} - SP_{\omega} \cdot \kappa^{\tau_{\omega}} \right] \geq 0 \tag{7}$$

The left-most component of Equation (7) is expanded to highlight the required amendments for expected cost competitiveness:

$$\sum_{t=1}^{T}[m \cdot x_t \cdot [CF_t - dCF_{t,\omega}] \cdot [a - da_{t,\omega}] \cdot (p_\omega - W_{t,\omega} - dW_{t,\omega})] \cdot \kappa^t$$

$$= \sum_{t=1}^{T} \left[m \cdot x_t \cdot \kappa^t \cdot [CF_t \cdot a - dCF_{t,\omega} \cdot a - CF_t \cdot a - dCF_{t,\omega} \cdot da_{t,\omega}] \cdot (p_\omega - W_{t,\omega} - dW_{t,\omega})\right]$$

$$= \sum_{t=1}^{T}[m \cdot x_t \cdot \kappa^t \cdot [CF_t \cdot a - dCF_{t,\omega} \cdot a - CF_t \cdot da_t - dCF_{t,\omega} \cdot da_{t,\omega}] \cdot (p_\omega)$$
$$- \sum_{t=1}^{T}[m \cdot x_t \cdot \kappa^t \cdot [CF_t \cdot a - dCF_{t,\omega} \cdot a - CF_t \cdot da_t - dCF_{t,\omega} \cdot da_{t,\omega}] \cdot (W_{t,\omega})$$
$$- \sum_{t=1}^{T}[m \cdot x_t \cdot \kappa^t \cdot [CF_t \cdot a - dCF_{t,\omega} \cdot a - CF_t \cdot da_t - dCF_{t,\omega} \cdot da_{t,\omega}] \cdot (dW_{t,\omega})$$

The expanded expression above is divided by the output of the incumbent asset, i.e.:

$$\sum_{t=1}^{T} m \cdot x_t \cdot a \cdot CF_t \cdot \kappa^t$$

By dividing by the output of the incumbent asset, one is able to isolate the incremental terms needed to guarantee investors break-even, relative to the expression presented in Proposition 1. The division leads to the expression below:

$$= (p_\omega) \cdot \left[1 - \frac{\sum_{t=1}^{T} x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t}\right] - (w_\omega) \cdot \left[1 - \frac{\sum_{t=1}^{T} W_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t}\right] - (dw_\omega) \cdot \left[1 - \frac{\sum_{t=1}^{T} dW_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t}\right] \quad (8)$$

where:

$$\lambda_{t,\omega} = dCF_{t,\omega} \cdot a - CF_t \cdot da_t - dCF_{t,\omega} \cdot da_{t,\omega}$$

Substituting the quotient above into Equation (7) yields:

$$\sum_{\omega} h(\omega) \Bigg[(p_{\omega}) \cdot \left[1 - \frac{\sum_{t=1}^{T} x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} \right] - (w_{\omega}) \cdot \left[1 - \frac{\sum_{t=1}^{T} W_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} \right]$$
$$- (dw_{\omega}) \cdot \left[1 - \frac{\sum_{t=1}^{T} dW_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} \right] - f_{\omega} - df_{\omega} - c_{\omega} - c_{\omega}^{c} \cdot \kappa^{\tau,\omega} \Bigg] \geq 0 \tag{9}$$

Which can be rewritten as:

$$\sum_{\omega} h(\omega) \cdot (p_{\omega}) \cdot \left[1 - \frac{\sum_{t=1}^{T} x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} \right] \geq \sum_{\omega} h(\omega) \Bigg[w_{\omega} + f_{\omega} + c_{\omega} + dw_{\omega} + df_{\omega} + c_{\omega}^{c} \cdot \kappa^{\tau_{\omega}}$$
$$+ \frac{\sum_{t=1}^{T} W_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} + \frac{\sum_{t=1}^{T} dW_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} \Bigg] \tag{10}$$

The terms on the right of Equation (10), which all involve cash flow terms, instead of price or solely adjustments for changes in capacity, represent the components of the expanded, stochastic LPC. From left to right, the terms are interpreted as follows:

$$\left[1 - \frac{\sum_{t=1}^{T} x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} \right],$$

The above is the adjustment factor to expected price to account for changes in output. The adjustment factor ensures that fixed and capital costs are covered at the proper time-averaged rate. This term is represented as Γ_{ω}.

$$w_{\omega} + f_{\omega} + c_{\omega},$$

The above terms are the baseline costs to be covered in the presence of uncertainty alone.

$$dw_{\omega} + df_{\omega},$$

The above terms are the changes in operational costs and do not themselves account for changes in output.

$$c_{\omega}^{c} \cdot \kappa^{\tau_{\omega}},$$

The above summarizes the levelized cost of incremental capital, without itself accounting for changes in output.

$$\frac{\sum_{t=1}^{T} W_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} + \frac{\sum_{t=1}^{T} dW_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t},$$

The above adjusts operational variable costs to account for changes in output.

For analytical convenience, define ϑ_ω as follows:

$$\vartheta_\omega = dw_\omega + df_\omega + c_\omega^c \cdot \kappa^{\tau_\omega} + \frac{\sum_{t=1}^{T} W_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t} + \frac{\sum_{t=1}^{T} dW_{t,\omega} \cdot x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t}$$

The stochastic, expanded LPC, which is the appropriate cost measure for long-term decision-making when the economic environment is characterized by uncertainty and managerial flexibility is given by:

$$\mathbb{E}_\omega[LPC] = \mathbb{E}_\omega[w_\omega + f_\omega + c_\omega + \vartheta_\omega]. \tag{11}$$

■

The terms on the left of Equation (10) summarize the appropriate comparison price with which to gauge the expected cost competitiveness of the asset. Allowing Γ_ω to represent $\left[1 - \frac{\sum_{t=1}^{T} x_t \cdot \kappa^t \cdot \lambda_{t,\omega}}{\sum_{t=1}^{T} x_t \cdot a \cdot CF_t \cdot \kappa^t}\right]$, the left hand side can be re-expressed as follows:

$$\mathbb{E}_\omega[p_\omega \cdot \Gamma_\omega] \tag{12}$$

Finally, the following expression summarizes the requirement for the asset to be cost-competitive in expectation and in the presence of both uncertainty and managerial flexibility:

$$\mathbb{E}_\omega[p_\omega \Gamma_\omega] \geq \mathbb{E}_\omega[w_\omega + f_\omega + c_\omega + \vartheta_\omega]. \tag{13}$$

B Assumptions from the Carbon Capture Illustration

It is assumed the incumbent natural gas power plant is able to accommodate such additional equipment, and be so-called "carbon-capture ready." Calculations make the following assumptions: Operation life = 30 years; Discount Rate = 8%; Tax Rate = 40%; Gas Price = \$6.13/mmBtu; (initial) Cost of Emissions = \$0/tCO_2, no operational life extension from addition of carbon capture capabilities.

Table 1: Baseline Cost Estimates

Stage	**Element**	**Unit**	**NGCC**
1	Net Capacity	MWe-net	632
1	CAPEX	\$/kW	830.3
1	Fixed OPEX	\$/kW-yr	25.08
1	Variable OPEX	\$/kWh	0.00205
1	Fuel Cost	\$/kWh	0.0476
1	Efficiency	%	51.6
1	Emissions	kg/kWh	0.355
1	**LCOE**	**\$/kWh**	**0.066**
2	Net Capacity	MWe-net	546
2	CAPEX (capture eq. only)	\$/kW	1,210.1
2	Fixed OPEX	\$/kW-yr	56.08
2	Variable OPEX	\$/kWh	0.00441
2	Fuel Cost	\$/kWh	0.0551
2	Efficiency	%	44.6
2	Emissions	kg/kWh	0.041
2	**LCOE**	**\$/kWh**	**0.080**

C Additional Results from the Nuclear Retirement Illustration

Figure 9 shows the wholesale electricity prices over time across the four states-of-the-world, including region values (green) and the U.S. average (orange).

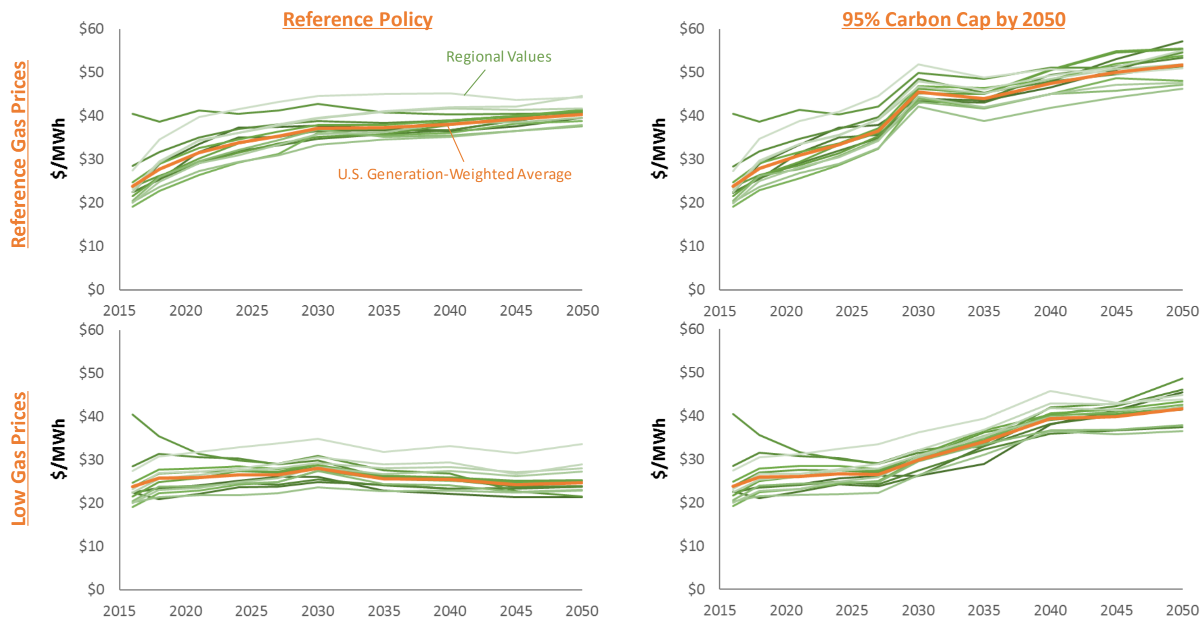

Figure 9: Wholesale electricity prices ($ per MWh) by scenario, region, and time. Regional values are shown in green with the generation-weighted national average in orange.

Figure 10 shows the net annual operating margin for an anonymized plant ("Plant X") separated by revenue and cost categories. These values show normalized margins by scenario assuming that the plant operates across the time horizon and does not retire before its license expires, which illustrates conditions under which it would be beneficial to retire (e.g., under high gas prices and reference policies) or to mothball (e.g., under high gas prices and stringent climate policy).

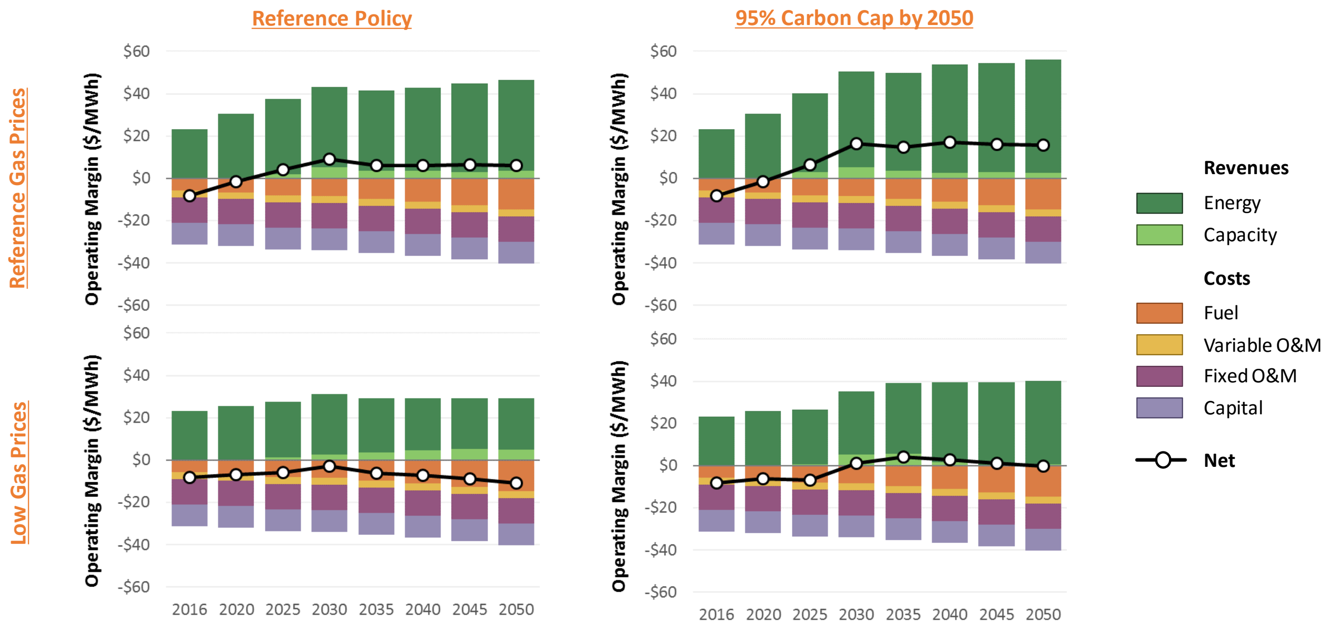

Figure 10: Net annual operating margin ($ per MWh) by cost category for Plant X, assuming hypothetical must-run dispatch.

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