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Distributed Generation and Path Dependency

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Abstract

Distributed generation (DG) provides energy and emissions savings for a single installation, provided consistent electricity and heat loads are available. But unless DG has a significant market penetration, it cannot be an important tool in meeting energy policy goals. Widespread use of DG represents an alternative system architecture for the generation and delivery of electricity and heat. A green-field cost optimization of seasonally varying energy system demands, showed utilization of DG provided overall cost savings of around 25%. This model was used to investigate the implications of introducing DG into an energy system with existing generation plant. Sizeable penetration of DG for base-load application results in system cost and emissions savings. However, a reduced utilization of 46% for existing capacity suggests potentially stranded assets. Ongoing modeling investigates endogenous implications of DG penetration including mechanisms for compensating stranded assets, natural gas costs, evolving demand and DG economies of scale.

Keywords: Distributed generation; Stranded assets; Path dependency.

1. Introduction

Technical and economic developments in distributed generation[1] (DG) represent an opportunity for a radically different energy system architecture (Patterson, 2000). IC engines are currently the most established gas-fired DG technology[2]. On-site use of residual heat together with avoidance of electricity transmission losses allow high overall efficiencies (up to 95% HHV). The potential of DG for cost and CO_2 savings has attracted considerable interest of policy makers (European Commission, 1997; NREL, 2000). DG requires consistent and well matched electricity and heat demands to deliver economic[3] and environmental benefits (GRI, 1999; Strachan, 2000).

The rate and magnitude of DG adoption will be influenced by technical, economic and regulatory changes in liberalizing energy markets (Azar and Dowlatabadi, 1999). New technologies within electricity and gas systems typically require a long time to diffuse, and this interlocking within networks presents additional hurdles to their widespread use (Grubler et al, 1999). A major issue in the evolution of electricity and gas markets are stranded assets. Investments in long-lived generation and transmission infrastructure have already been made by energy companies. They expect to recover these investments through operating revenues. If these investments are replaced prematurely, then capital is not recovered. This is an example of path dependency (Arthur, 1994), where historical actions or circumstances may impact current and future options (Ruttan, 1996).

The overall cost, fuel use and emission advantages that DG can offer to an entire system is discussed in (Strachan and Dowlatabadi, 2001), and is summarized in section 2. However, these savings are dependent on the initial state of the energy system, and thus on existing investments in generation technology. This paper details preliminary modeling efforts of the implications of DG adoption within an integrated electricity and heat generation and delivery network (section 3). This focuses on possible stranded assets due to DG adoption. Ongoing work (section 4) investigates further implications of DG introduction, including access to and payment for existing energy networks, changes in natural gas costs, evolving demand, and economies of scale (both capital and maintenance) for DG.

2. A Green-Field System Optimization of DG

2.1 Model overview

If an integrated electricity and heat production and delivery system was constructed with no prior generation or delivery infrastructure, what would be the optimal system architecture? An optimization model was developed to minimize total investment and operating costs to meet seasonally varying power and heat requirements over a 15 year time horizon. The green-field

[1] On-site energy facilities enable co-generation of electricity and heat for high efficiency of overall energy use (or even tri-generation of electricity, heat and cooling).
[2] For example, as of 1998 IC engines of <1MWe accounted for 6% (i.e. 1,500 MWe) of installed electrical capacity in the Netherlands (CBS, 1998).
[3] Economies of scale in maintenance costs are also important (Strachan and Dowlatabadi, 1999)

model assumes no initial plant or networks to compare optimal DG and conventional supply systems. A mixed integer linear program (MILP) selects fixed investments in energy technologies and their operation regime, from a variety of centralized-distributed and electricity-heat-cogeneration options. Full details of the derivation of input technology and demand parameters, and the detailed specification and testing of the MILP model is given in (Strachan and Dowlatabadi, 2001).

Table 1 summarizes the MILP optimization model to minimize total costs (C_T) of meeting power and heat requirements. The table lays out the components of the objective function, model indices, decision variables, demand constraints, and the energy outputs from each technology.

	Equation	Explanation
Objective function	$\min(\sum_{j,q,b,j,i,k} C_{TOT}$ $C_{TOT} = (C_K + C_T + [C_{OM} + C_F])$	Minimize the cost of meeting variable electricity and heat demand
Indices	t	Time horizon (15 years). Pro-rated capital costs, all variable costs - discounted at 10%
	q	Yearly season (summer, shoulder, winter)
	b	Temperature bands (hrs): max 1% (29hrs), high 9% (263 hrs), ave. 80% (2,336hrs), low 9% (263hrs), min 1% (29hrs)
	j	Technologies: power, heat or cogen
	i	Transmission network: elec, gas & heat
	k	Demand: residential, commercial, industrial
Costs	$C_K = \sum_j (K*\#*X,Y)$	Capital costs of technologies: K is cost per kW, X is electrical capacity, Y is heat capacity, and # is number of plant
	$C_T = \sum_{j,i} (T*\#*X,Y)$	Cost of energy transmission for electricity, gas and heat: T is trans. cost per kW
	$C_{OM} = \sum_{j,b,q,t} ([OM_1 + (OM_2 * h)]*\#*X,Y)$	OM_1 is O&M cost per kW, OM_2 is O&M cost per kWhr, h is hours run
	$C_F = \sum_{j,b,q,t} (F * h*\#*[X,Y/E])$	Fuel cost (natural gas): F is fuel cost per input kW, E is plant efficiency
Decision variables	#	Number of plants (integer)
	h	Hours run
Demand constraints	$\sum_{j,t,q,b,k} (X*\#*h) \geq Qe(b)$	Meet or exceed electrical demand (Qe) each period (variable by temp. and season)
	$\sum_{j,t,q,b,k} (Y*\#*h) \geq Qh(b)$	Meet or exceed heat demand (Qh) each period (variable by temp. and season)
Electricity output	$Qe = \sum_{j,b,q,t,k} (L * G * X*\#*h)$	Where L and G are electricity and gas transmission efficiencies
Heat output	$Qh = \sum_{j,b,q,t,k} (H * G * Y*\#*h)$	Where H is heat transmission efficiency
Additional constraints	$Qh(j,k) \leq availableQh$	Large cogen techs heating load restriction
	$h(b,j) \leq h(\max b)$	Plant operating hrs less than hrs per period
	$A(j) \leq 7884$	90% plant availability
	$h \geq 0, \# \geq 0$	Non negativity constraints
	$\#(j) = \text{integer}$	Number of plants must be an integer value

Table 1: MILP Optimization model equations

Table 2 details the energy technologies the optimization model can select by size range and energy output. These technologies represent the current convention of larger scale electricity generation and smaller scale on-site heat production.

	Centralized (>100MW)	Intermediate (1-50MW)	Distributed (100kW - 1MW)
Electricity only	Combined cycle gas turbine (CCGT) Coal fired steam turbine	Gas turbine (elec)	
Heat only			Gas fired boiler
Cogeneration		Gas turbine	Gas fired IC engine

Table 2: Energy technologies in optimization model

Table 3 summarizes the input specifications of the available technologies. Data on capital and O&M costs vary by source. Differences include site specific nature of costs (particularly for larger generating plant), financing and ownership structure, and base-load vs. peak operation for per kWh costs. Cogeneration plants generally entail higher capital and O&M costs than electricity-only counterparts due to additional components (heat exchangers etc). Estimation difficulties of plant efficiencies include plant design and confusion between HHV and LHV values. Heat to power ratios (HPR) determine heat output with a total available efficiency chosen at a typical cogeneration value of 90% (HHV).

Transmission costs for electricity, gas (and coal) and heat networks entail the same estimation problems as capital and O&M costs. System design and the quantity of energy to be transferred are especially important. The model estimates costs using the difference in energy prices (EIA, 1999) from production facilities to centralized, intermediate and distributed energy users as a bound on the costs of transmission[4]. A full source list for parameter values is available.

Technology	Units	Steam turbine	CCGT (elec)	Gas turbine	GT (elec)	IC Engine	Heat boiler
Capital cost	$/kWe	600	550	500	400	700	200
Fixed O&M cost	$/kWe	15	15	15	15	15	10
Variable O&M cost	(¢/kWh)	0.4	0.55	0.55	0.4	0.7	0.2
Gas/coal price[5]	¢/kWhr	0.42	0.89	0.89	0.89	0.89	0.89
Lifetime	years	30	30	20	20	15	20
Capital cost Recover in 15 yrs	$/kWe	497	456	459	367	700	184
Electricity trans. cost	¢/kWhr	1.88	1.88	0.77	0.77	0.24	-
Gas/coal trans. cost	¢/kWhr	0.08	0.04	0.13	0.13	0.44	0.44
Heat trans. cost	¢/kWhr	1.32	-	0.88	-	0.26	0.26
Elec. network efficiency	%	91.7%	91.7%	95.8%	95.8%	100%	-
Gas network efficiency	%	99.3%	99.3%	99.0%	99.0%	98.7%	98.7%
Heat network efficiency	%	80.8%	-	94.3%	-	98.1%	98.1%
Plant efficiency	%	36%	55%	34%	34%	29%	92%
Maximum HPR	#	1.5	-	1.65	-	2.1	-
Electrical Size	kWe	500,000	100,000	10,000	10,000	500	-
Heat Size	kWth	750,000	-	16,470	-	1,050	500

Table 3: Optimization model sample parameters

[4] When aggregating user categories, electricity and gas transmission costs are the averaged price bound. Heat transmission costs are constant with the available heating load restricted by technology and user category.

[5] For our model values: 0.89 ¢/kWhr for natural gas = 2.74 $/m cu.ft. 0.42 ¢/kWhr for coal = 29 $/short ton

The green-field cost optimization model was applied to the electricity and natural gas systems of two US states: New York with heat, and Florida with electricity dominated seasonality and heat to power (HPR) characteristics. Temperature data was translated into variable energy demands. Annual operating hours are discretized by season, and further divided by variable consumption demand times based on temperature. This approximates a load duration curve. We are particularly interested in extreme temperature variations as these provide measures of peak electricity and heat demands. Daily variation is not considered and the scale of analysis implicitly aggregates site loads.

New York is a heat dominated system with an average HPR of 2.1:1. Florida's electricity requirements are proportionally larger, with an average HPR of 1.3:1. New York has its largest heat demands in winter/coldest temperature bands, together with some electric heating. In addition, New York's energy demand has more variability. Florida has its proportionally larger electricity demands at their highest in summer/warmest temperature bands.

2.2. Cost Implications of DG vs. Conventional Supply

Provided that consistent electricity and heat load are available, DG is the lowest cost technology for a single application. By restricting the technologies available to the model, optimal system solutions using DG can be compared an energy system using conventional electricity-only and heat-only technologies. Will DG provide economic savings for an entire system?

Using the aggregated demands for New York and Florida, Table 4 gives the technology selection and overall costs (over 15 years) when using electricity or heat-only technologies, when allowing progressively smaller cogeneration technologies, and lastly when allowing DG.

NEW YORK	Technology choice and use	Optimal cost (M$) (and savings)
No cogen technologies at all	Electric base-load: 33 CCGTs, peak electric needs: 4,830 gas turbines, heat needs: 256,180 large boilers	183,410
None of micro-engines, engines, cogen gas turbines	Base-load: 56 steam turbines, peak electric needs: 2,460 gas turbines (elec), peak heat needs: 189,050 large boilers	169,880 (7.4% decrease)
None of micro-engines, engines	Base-load: 5,150 cogen gas turbines, additional heat: 89,080 large boilers	149,040 (18.7% decrease)
No micro-engines	As above	135,340 (26.2% decrease)
ALL	Base-load: 98,930 engines, additional heat: 4,430 large boilers	135,340 (26.2% decrease)
FLORIDA	**Technology choice and use**	**Optimal cost (M$) (and savings)**
No cogen technologies at all	Electric base-load and peak: 4,210 gas turbines, heat needs: 5,880 large boilers	97,730
None of micro-engines, engines, cogen gas turbines	Base-load: 32 steam turbines, peak electric needs: 2,670 gas turbines, peak heat needs: 19,198 large boilers	92,750 (5.1% decrease)
None of micro-engines, engines	Base-load: 1,860 gas turbines (cogen), additional electricity: 2,350 gas turbines	80,280 (17.9% decrease)
No micro-engines	Base-load: 28,046 engines, additional electricity: 2,745 gas turbines	77,120 (21.1% decrease)
ALL	Base-load: 28,040 engines, additional electricity: 2,750 gas turbines, 1 micro-engine for residual	77,110 (21.1% decrease)

Table 4: DG, cogeneration and conventional supply solutions: New York and Florida

Savings due to DG and cogeneration are substantial compared to conventional energy supply. As the available size of the cogeneration technology gets smaller, savings increase, owing both to the improved costs of gas turbines and then IC engines, and also as these smaller units can be used more flexibly to meet variable load. Compared to conventional electricity and heat-only technologies, use of DG results in system cost savings of 26% and 21% in New and Florida. New York realizes higher percentage cost savings from DG as its greater heat demand allows the large heat output from IC engines to be utilized. Florida's large electricity requirements ensure electricity-only gas turbines remain a significant part of the generating capacity.

3. Path Dependency in a Future Transition to DG

As a system with significant DG penetration offers costs savings for production and delivery of electricity and heat, what are the impacts of implementing DG capacity into an existing system? Preliminary results, focusing on stranded assets, are given in this section whilst section 4 outlines a more complete range of implications of DG adoption to be modeled.

The MILP cost optimization model detailed in section 2, is used to investigate the evolution of energy technologies used for the integrated supply of electricity and heat for Florida. Overall system cost, generation plant mix, plant operating methodology, natural gas use and emissions of CO_2, SO_2 and NO_X are calculated through 30 years of system evolution.

The model is firstly run (t=0) without distributed IC engines or cogen gas turbines. This generates our starting conditions. The demand parameters for Florida give an initial mix of base-load steam turbines and heat boilers, with electricity-only gas turbines for summer peaking times. The system is then optimized every three years with retirals of existing plant changing the prior generation mix. Lowest cost technologies are expected to be chosen with resulting impacts on utilization of existing plant. The age of existing plants are assumed to be uniformly distributed with the expected lifetime per technology.

Thus at any time (t), the existing plant mix will be:
[original plants (t_0)] – [retirals (t_{-3}, t_{-6}…)]
+ [new plant (t_{-3}, t_{-6}…)] – [new plant retiral ($t_{-\text{plant lifetime}}$)]

Assumptions[6] include:

- Energy delivery networks can be utilized (and paid for) by all technologies (cogen technologies have an extra system integration cost)
- Time steps of 3 years are sufficient for bringing new plant on-line
- Constant demand over a 30 year period (10 runs)
- Constant capital and O&M costs
- Constant fuel prices

Figures 1 and 2 illustrate the evolution of the Florida energy system in terms of installed capacity and generation. Also shown on the right side is the optimal solution given if all technologies were available and with no existing plant.

Distributed generation (in this model gas-fired IC engines) is introduced as the lowest cost technology, as electricity-only steam turbines and heat-only boiler plants are phased out. Gas turbines and CCGT plant are restricted to less than 5 units[7]. The system configuration resembles the optimal solution as more older plant is retired.

However, the installed DG capacity is run at base-load (maximum hours) for greatest energy and costs savings. Therefore, the existing base-load plant is dispatched for fewer hours per annum as DG becomes base-load. This is apparent as generation from steam turbines and heat boilers is much less than capacity. In addition there is over-capacity for heat provision as IC engines are initially introduced. This different system operation suggests possible stranded assets.

[6] Section 4 outlines future modeling where these assumptions are relaxed
[7] Hence are not displayed in Figures 1&2 for clarity

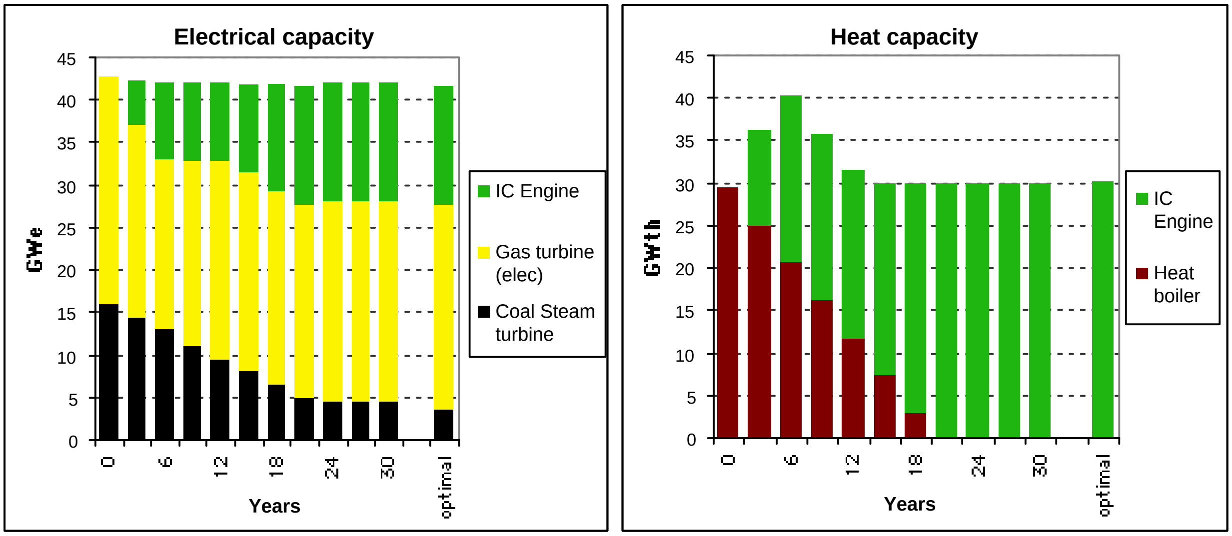

Figure 1: Evolution of system energy capacity

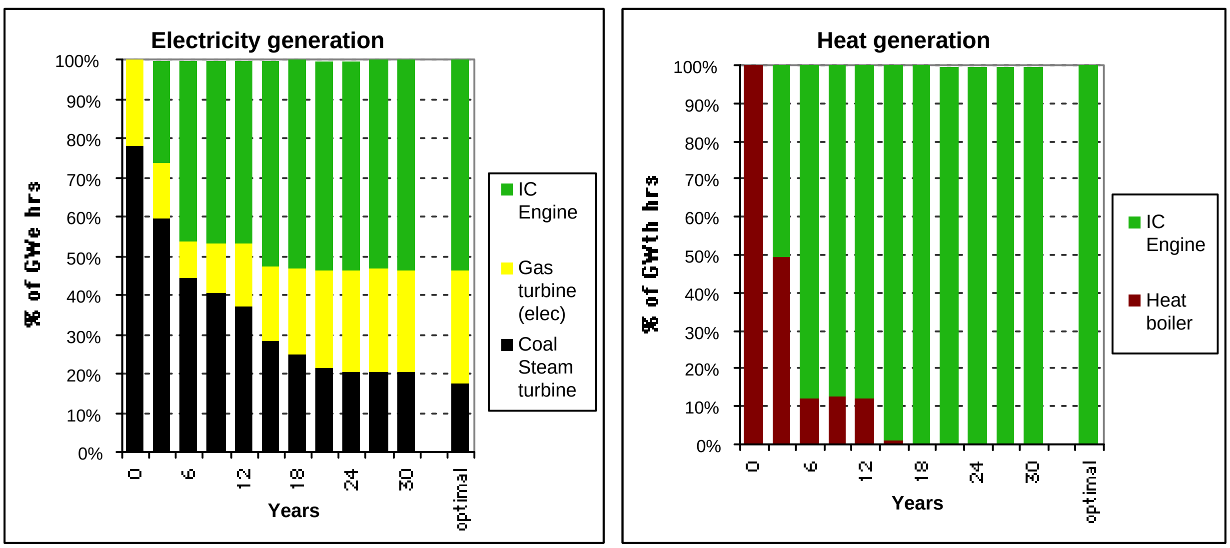

Figure 2: Evolution of system energy generation

What are stranded assets? Investments in long-lived generation and transmission infrastructure have already been made by energy companies. They expect to recover these investments through operating revenues. If these technically serviceable investments are replaced prematurely, then capital is not recovered.

The discussion considers generation assets for simplicity. If existing plants have load factors less than originally specified, they will either not recover investment costs and are therefore stranded assets or their costs will be borne by the remaining customers in which case private investment in DG will have placed a financial externality on this third party. Table 5 presents the differences in utilized and planned GWhrs for existing plant.

(Years)	**Coal steam turbine**	**CCGT (elec)**	**Gas turbine (elec)**	**Heat boiler**	**Total**
3-5	-59,457	985	-22,411	-180,660	-261,543
6-8	-97,781	1	-47,525	-377,338	-522,643
9-11	-70,517	1,085	-22,494	-278,986	-370,912
12-14	-49,791	971	-11,342	-196,573	-256,735
15-17	-57,058	-22	-2,279	-197,461	-256,821
18-20	-38,918	0	3,571	-127,327	-162,674
21-23	-18,264	0	2,985	8,798	-6,481
24-26	-7,318	0	0	0	-7,318
27-29	-3,375	0	0	0	-3,375
Total	-402,479	3,021	-99,495	-1,349,548	-1,848,501
% difference	**-24%**	**+61%**	**-25%**	**-70%**	**-46%**

Table 5: GWhrs discrepancy from possible stranded generation assets

Table 5 confirms the intuition from the mismatch in capacity and generation from existing plants. There is considerable under-utilization for electricity–only steam turbines and gas turbines, and especially heat boilers. In total there is a loss of 46% of expected generation over the 30 years period in which initial plants still operate. Heat boiler plant experiences the largest under-utilization, losing 70% of expected generation. Such potential for non-recouped investments may be a barrier to widespread DG utilization.

Turning to the added capacity, this is primarily IC engines for base-load and gas turbines for peak electricity needs (Florida has a large summer electricity requirement). Table 6 details the number and operating methodology of new capacity. By years 27 and 30 (when the last of the initial plant is retired) system capacity changes are in balance, with new capacity equaling retirals. As load factors are fairly consistent, stranded asset issues are not of such concern to new capacity additions

Throughout the 30 year period, gas turbine additions are relatively constant. However IC engine additions vary widely from 8,000 to 0 units added in a three year span. Such a large addition of DG into a system may pose technical constraints. The rapid deployment of DG in Netherlands, saw the highest 3 years addition (from 1993-1995) to be around 2000 units (CBS, 1998). This caused concern from some energy industry observers as to the system consequences, including over-capacity. Can a system successfully integrate 8,000 units in 3 years? In addition, from a supplier perspective installing 18,000 units in 6 years and then 3 in the next 6 years poses great challenges, even if servicing and operation activities continue. Limits on DG capacity additions may need to be imposed.

	years	3	6	9	12	15	18	21	24	27	30
Gas turbine (elec)	new plant	0	134	592	544	403	333	264	94	134	592
	hrs run	0	1600	924	1068	1254	1504	1698	1700	1698	1700
	retirals	0	0	0	0		0	0	0	134	592
IC engine	new plant	10439	7856	3	0	2711	4205	13185	7853	17	0
	hrs run	7884	7881	7884	7884	7742	6526	5897	6375	5895	6869
	retirals	0	0	0	0	0	0	10439	7856	3	0

Table 6: Generation plant additions

Two final impacts of DG introduction are natural gas use and emissions of CO_2, SO_2, and NO_X. Overall natural gas changes depend on the technologies that are replaced. For an entirely gas system (e.g. CCGT and heat boilers) DG reduces gas use for Florida by around 24%, with greatest savings when heat to power ratios (HPR) of demand and DG output are matched. Conversely, if coal steam turbines are in the original mix, DG replacement increases gas use by around 30%. Such variations would have consequences for the wellhead price and transmission costs for natural gas.

Emissions of CO_2, SO_2 and NO_X are all reduced under widespread penetration of DG. For Florida, the final DG dominated generation mix is compared to the original mix of coal steam turbines, gas turbines for peak electricity demands and gas fired boilers, using emissions factors per technology (EPA, 1998). CO_2 emission are reduced by 32% through efficiency gains, SO_2 by 75% as coal plants are retired, and NO_X is reduced by 53% (providing IC engines are catalytic controlled).

4. Discussion

Unless distributed generation (DG) has a significant market penetration, it cannot be an important tool for energy and emissions savings. Widespread use of DG represents an alternative system architecture for the generation and delivery of electricity and heat. A green-field cost optimization of Florida's seasonally varying energy demands showed utilization of DG provided cost savings of around 25%.

This model was used to investigate the implications of introducing DG into an energy system with existing generation plant. Preliminary modeling showed sizeable penetration of DG for base-load application. The system configuration resembles the optimal solution as more older plant is retired, with resultant cost and emissions savings. However, a reduced utilization of 46% for existing capacity suggests potentially stranded assets. In addition rapid deployment of DG presents challenges for incorporation into existing energy networks and for DG suppliers.

Ongoing modeling investigates endogenous implications of DG penetration into an integrated energy system with existing generation capacity. This will focus on:

- Mechanisms to alleviate losses from stranded generation assets
- Changing natural gas use and cost implications, including seasonal variations in gas use and effects of transmission congestion
- Limitations on the rate of change towards a DG dominated system
- Regulatory mechanisms for emissions of pollutants, including temporal and spatial considerations for local air pollutants
- Technological change in available supply technologies
- Potential stranded assets and compatibility issues for energy delivery networks
- Evolving demand, including medium term responses to price signals
- DG economies of scale in capital costs and especially geographical economies of scale in DG O&M costs.

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