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The Capacity Value of Wind in the United States: Methods and Implementation

As more wind energy capacity is added in the nation, the question of wind's capacity value is raised. This article shows how the capacity value of wind is determined, both in theory and in practice.

Michael Milligan and Kevin Porter

I. Introduction

A fundamental element of the electric industry is not only to ensure generating capacity to meet customer demand but also to have generating capacity in reserve in case customer demand is higher than expected or a generator or transmission line goes out of service. Although a basic concept, the methods used for evaluating capacity adequacy are strikingly different from region to region.

With nearly 7 GW of installed wind capacity in the United States at the end of 2004 and another 2.5 GW expected to have come on-line in 2005, the question of whether wind energy is a capacity resource is gaining more attention. Wind's variability makes this a matter of great debate in some regions. However, many regions accept that wind energy has some capacity value, albeit at a lower value than other energy technologies. Recently, studies have been published in California, Minnesota, and New York that document that wind energy has some capacity value. These studies join other initiatives in the Pennsylvania–Jersey–Maryland (PJM) RTO, Colorado, and in other states and regions.

Wind generators occupy a unique place in the determination

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of capacity value. Wind generators have typically very high mechanical availability, exceeding 95 percent in many instances (i.e., the forced outage rate is often below 5 percent). However, because wind generators only generate electricity when the wind blows, a wind generator arguably has a forced outage when the wind does not blow. Therefore, the effective forced outage rate for wind generators may be much higher, from 50 percent to 80 percent, when recognizing the intermittent availability of wind. In addition, wind's value to the electric system may also vary. The output from some wind generators may have a high correlation with load and thereby can be seen as supplying capacity when it is most needed. In this situation, a wind generating plant should have a relatively high capacity credit.[1]

This article focuses on different methodologies for determining the capacity value of wind energy. It summarizes several important state and regional studies that examine the capacity value of wind energy, how different regions define and implement capacity reserve requirements across the country, and how wind energy is defined as a capacity resource in those regions.[2] We will start with a discussion of effective load carrying capability (ELCC), consider how capacity credit is derived in practice, and explore the fallacy of applying a random statistical probability to the capacity value. We close with a summary.

II. Effective Load Carrying Capability

ELCC is based on well-established reliability theory and practice and can be applied to all generators. ELCC is based on one of several reliability metrics, such as loss of load probability (LOLP), loss of load expectation (LOLE), or expected unserved energy (EUE). ELCC can be calculated with a power system reliability model, with appropriate tweaking to properly account for the stochastic and variable nature of wind generation. ELCC can discriminate among generators with differing levels of reliability, size, and on-peak versus off-peak delivery. It effectively rewards plants that are consistently able to deliver during periods of high demand and ranks less reliable plants by calculating a lower capacity credit. For intermittent generators such as wind, the method can discriminate between wind regimes that consistently deliver during high-risk periods, sometimes deliver during high-risk periods, or never deliver during high-risk periods.

ELCC is based on well-established reliability theory and practice and can be applied to all generators.

To calculate ELCC, a database is required that contains hourly load requirements and generator characteristics. For conventional generators, rated capacity, forced outage rates, and maintenance schedules are the primary requirements. For an intermittent resource such as wind, at least one year of hourly power output is required, but more data is always better. Over the decades that ELCC has been applied, it has been used with a number of different reference units. Some early work measured the capacity value of a generator against a perfectly reliable unit.[3] Because such a unit does not exist, we prefer the alternative of measuring capacity value relative to a benchmark unit. In any event, it is important that the benchmark unit is clearly identified, and *all* units in a given region should be measured against the same benchmark. **Figure 1** illustrates the ELCC of a hypothetical generic plant, relative to a benchmark gas unit. Because the benchmark unit has a combined outage rate of 10 percent (maintenance and forced), the generic unit can achieve an ELCC value of 100 percent of the benchmark if the generic unit has a 10 percent forced outage rate. But 100 percent of the benchmark is approximately 90 percent of the plant rated capacity.

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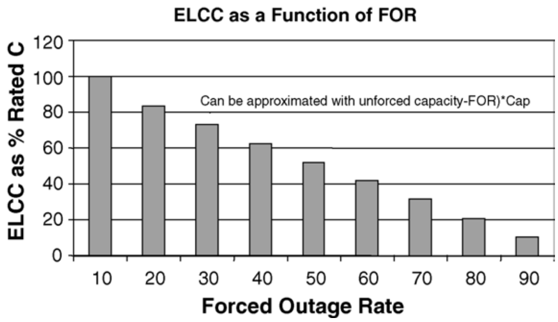

Figure 1: The ELCC of Generic Conventional Generator with Alternative Forced Outage Rates

Although there are some variations, ELCC is calculated in several steps. Most commonly, the system is modeled without the generator of interest. For this discussion, we assume that the generator of interest is a renewable generator, but this does not need to be the case. The loads are adjusted to achieve a given level of reliability, such as a loss of load expectation of 1 day per 10 years. This LOLE can be calculated by taking the LOLP (a probability is between zero and 1 and cannot by definition exceed 1) multiplied by the number of days in a year. Thus LOLE indicates an expected value and can be expressed in hours/year, days/year, or some other unit of time.

Once the desired LOLE target is achieved, the renewable generator is added to the system and the model is re-run. The new, lower LOLE (higher reliability) is noted, and the renewable generator is removed from the system. Then the benchmark unit is added to the system in small incremental capacities until the LOLE with the benchmark unit matches the LOLE that was achieved with the renewable generator. The capacity of the benchmark unit is then noted, and that becomes the ELCC of the renewable generator. It is important to note that the ELCC documents the capacity that achieves the same risk level as would be achieved without the renewable generator.

To derive the ELCC of wind, one ideally would have access to several years of wind generation data, load data, and other generation data. But because a long wind generation record often does not exist, it is reasonable to expect that wind's capacity value could vary from year to year. One way to help solve the problem of the year-to-year variability of the capacity value for wind is to create wind generation scenarios using meso-scale meteorological models. For the Minnesota Department of Commerce (MN/DOC) wind integration study, Enernex and WindLogics developed a three-year wind data record by re-creating the actual weather and normalizing to the long-term trend.[4] A variation of this approach may involve the re-creation of several additional years of weather data, then running the reliability model for each of these several years to capture a longer time period.

A. Factors that influence the ELCC of wind

Regardless of the method used to calculate wind ELCC, a number of factors can influence the results. The key influence is the timing of the wind delivery relative to times of significant LOLP (when the 1-day-per-10 years LOLE is used, significant LOLP is generally a non-zero LOLP for the hour in question). Wind that delivers significant capacity during the times of system risk achieves a high capacity value. Conversely, wind that generates little or no output during these high-risk periods will have a low or zero capacity value. In addition, hourly LOLP is subject to several influences, such as the mix of other generation units and the generation units' and forced outage rates. The way that these parameters interact with the load has an important influence on LOLP.

In a system with significant hydro generation, there can be two additional influences on LOLP. The first is from the non-controllable hydro (run of river) that has arbitrary influences on LOLP. This influence will vary from year to year as a function of the hydro flow and changing load shape. Controllable hydro is generally operated so that it benefits the system in some optimal way. Generally, controllable hydro is used to mitigate high risk

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and therefore will reduce LOLP during peak periods. This has the effect of altering the shape of the LOLP curve and can perhaps shift the highest risk hours to near-peak hours from peak hours.

Off-system purchases can also influence the risk profile. Because system operators want to ensure sufficient resources during peak periods, it is not uncommon to schedule purchases during peak periods. Of course, that will influence the risk profile and the ELCC of wind.

Maintenance on generators is normally deferred to off-peak months in the spring or fall. This is done for obvious reasons: the system operator wants to ensure that all generation is available during the peak periods when the system is most constrained and at highest risk. Because of generators being off-line for scheduled maintenance, it is not uncommon for the spring or fall maintenance periods to drive up the system risk to levels at or near those found during peak periods. This significantly alters the risk profile, and therefore it can play a large role in determining the ELCC of a wind plant.

B. Approximation methods for ELCC

Because of the potential difficulty of assembling the appropriate database to use for the ELCC calculation, interest in simpler methods has emerged over the past several years. Although several methods can be used to approximate ELCC, an unfortunate aspect of all of these methods is that they are indeed approximations.

Broadly speaking, the approximation techniques fall into two categories: risk-based or time-period-based. Risk-based categories develop an approximation to the utility's LOLP curve throughout the year. Time-period-based methods attempt to capture risk indirectly, by assuming a high correlation between hourly demand and LOLP. Although this relationship generally holds, it can be compromised by scheduled maintenance of other units and hydro conditions. A further limitation of time-period-based methods is that all hours considered by the method are generally weighted evenly, whereas ELCC and other risk-based methods place higher weight on high-risk hours and less weight on low-risk hours. However, time-period-based methods are much simpler and are easy to explain in regulatory and other public proceedings.

A more common approach is to use time-period methods that allow the avoidance of reliability model.

Risk-based methods utilize hourly LOLP information either from a reliability model run or as an approximation. One widely known method, described by Garver (1966), can be applied to wind.[5] The Garver technique was developed to estimate ELCC of conventional generators and to overcome the limited computational capabilities that were available at the time. The technique is based on the development of a risk-approximation function.

The approach approximates the declining exponential risk function (LOLP in each hour, LOLE over a high-risk period). It requires a single reliability model run to collect data to estimate Garver's constant, known as m. Once this is done, the relative risk for an hour is calculated by Garver's approximating equation.[6] To use this approach for wind generators simply involves the application of the Garver equation to the net load after subtracting the wind generation. The output of a benchmark unit can be similarly applied to the approximating equation so that the wind ELCC can be approximated relative to the benchmark unit.

A more common approach is to use time-period methods that allow the avoidance of a reliability model. To do so, hourly load and wind data should be collected for at least one year. The data can be used to calculate an approximation to ELCC. This approach is appealing in its simplicity, but it does not capture the potential system risks that are

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part of the other methods discussed above.

One of the most straightforward approaches is to calculate the wind capacity factor (ratio of the mean to the maximum) over several times of high system demand. An early study using this method calculated capacity factors for wind for the top 1 percent to 30 percent of loads, using an increment of 1 percent. The results show that at approximately 10 percent or more of the top load hours, the capacity factor is within a few percentage points of the ELCC.[7]

Several of the approaches below use time-period methods to calculate wind capacity value, and the remainder of this article will be devoted to various forms of time-period methods.

III. Capacity Credit in Practice

In this section we survey some of the approaches to evaluating the capacity credit of wind. These methods come from a variety of entities, including regional transmission organizations, public utility commissions, utilities, and studies carried out on behalf of these organizations.

PJM: The capacity credit for wind in PJM is based on the wind generator's capacity factor during the hours from 3 p.m. to 7 p.m., from June 1 through Aug. 31. The capacity credit is a rolling three-year average, with the most recent year's data replacing the oldest year's data. Because of insufficient wind generation data, PJM has applied a capacity credit of 20 percent for new wind projects, to be replaced by the wind generator's capacity credit once the wind project is in operation for at least one year. As an example, a new wind generator will receive a capacity credit of 20 percent the first year; the average of 20 percent and the wind generator's capacity factor during the hours from 3 p.m. to 7 p.m. from June 1 through Aug. 31 in the second year; and the average of 20 percent and the wind generator's capacity factor during the hours from 3 p.m. to 7 p.m. for June 1 through Aug. 31 for years two and three, and so on.[8]

One of the most straightforward approaches is to calculate the wind capacity factor over several times of high capacity demand.

New York Independent System Operator (NYISO): The NYISO allows wind projects larger than 1 MW capacity to qualify for capacity credit. Wind generators can submit the results of a four-hour sustained maximum output test, for summer (June 1 through Sept. 15) and winter (Nov. 1 through April 15). The results of the tests are the wind generator's initial capacity credit in the NYISO. The NYISO adjusts the capacity credit monthly based on data submitted by the generator on actual generation and maintenance hours the previous month.[9] A 2005 study by General Electric (GE) for the New York State Energy Research Development Authority (NYSERDA) found that onshore wind projects had a lower capacity value (9 percent) than is currently provided to wind by the NYISO.[10] The NYISO will likely investigate changing the methodology for determining the capacity credit of wind.

ISO New England: Three wind generators are registered with ISO New England, at a total capacity of about 1.5 MW, so ISO New England has not closely examined the capacity value issue of wind. Currently, wind generators receive a capacity credit equal to the unit's capacity, multiplied by 1 minus its forced outage rate.[11] ISO New England may re-examine this method if the 420 MW Cape Wind offshore wind project off the coast of Massachusetts becomes operational.

Southwest Power Pool (SPP): SPP adopted a method to calculate the capacity contribution of wind. The SPP method is a monthly method, and therefore it results in 12 capacity measures for the wind plant. The process first examines the highest 10 percent of load hours in the month. Wind generation from those hours is then ranked from high to low. The wind capacity value is selected from this ranking, and it is the value that is exceeded 85 percent

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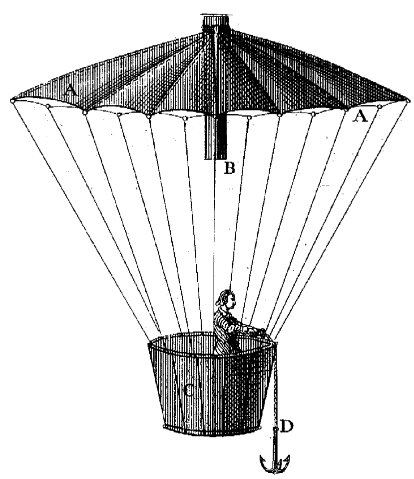
of the time (the 85th percentile). Up to 10 years of data are used if available. For the wind plants studied in the SPP region, the capacity values ranged from 3 percent to 8 percent of rated capacity. According to a 2004 presentation from the SPP's Generation Working Group (GWG), this method is used for long-term planning.[12] Although it appears counterintuitive to us, the SPP's GWG believes that ELCC/ LOLP methods are better used to determine the level of desired spinning or operating reserves and not to determine the reliability impacts of wind.

GE/NYSERDA: The aforementioned GE study for NYSERDA examined the impact of 3,300 MW of wind on the New York bulk power system. Although the study focused on reliability impacts and operational issues, the team assessed the capacity contribution of wind using ELCC. The study used simulated wind data from more than 100 sites throughout the state, matched to the year of load data. This important step accounts for any underlying systematic correlation that may exist between wind and load. (This correlation would be expected to vary by region, and it would likely be nonlinear with a potentially complex lag structure.) The study found that on-shore wind plants would be expected to have approximately 9 percent capacity value relative to rated capacity, and off-shore wind would be approximately 40 percent. For the on-shore wind scenarios, the modelers found that a time-period based approach was effective at approximating the capacity value. For the summer season, the wind capacity factor was measured during the hours from 1 p.m. to 4 p.m.[13]

Minnesota Department of Commerce/Xcel (MN/DOC): The MN/ DOC study examined the impact of 1,500 MW of wind capacity distributed at various locations in



southwest Minnesota. This represented approximately a 15 percent wind penetration on Xcel Energy's system, based on the ratio of rated wind capacity to peak load. One of the study tasks was to calculate the capacity contribution of wind. The study used a sequential Monte Carlo (SMC) method, which performed repeated sampling of an annual state transition matrix that was calculated based on the wind data used in the study. The intent of this approach is to capture some of the impact of the interannual variation of wind so that estimates of ELCC may be more robust. The SMC cases found a 26.7 percent capacity contribution for the prospective wind plants. For comparison, the study also used a simple ''load-modifier'' method that calculates reliability based on a simple netting of the wind generation against hourly load. When this approach was used, the prospective wind capacity value was 32.9 percent of rated capacity.[14]

Pacificorp: In its 2005 integrated resource plan (Pacificorp 2005), Pacificorp modeled wind generation using the same sequential Monte Carlo approach used by Enernex in the MN/DOC study. For the several prospective wind locations analyzed by PacifiCorp, the capacity contribution of wind averaged approximately 20 percent of rated capacity.[15]

Electric Reliability Council of Texas (ERCOT): ERCOT evaluated the operating wind plants to determine the capacity contribution of wind. The analysis was based on wind generation from 4 p.m. to 6 p.m. during July and August, the peak period for ERCOT. During this time period, the average output of the wind was 16.8 percent of rated capacity. Because of the variability of wind generation, the ERCOT Generation Adequacy Task Group is developing a confidence factor. Although the method of evaluation of this confidence factor is unclear, the recommendation under consideration is to use 2 percent of rated wind capacity as the capacity value.[16]

Mid-Continent Area Power Pool (MAPP): The MAPP approach is a monthly method that calculates wind capacity value based on the timing of its delivery relative

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to peak. Up to 10 years of data (wind and load) can be used if available. For each month, a four-hour time window surrounding the monthly peak is selected. Any contiguous four-hour period can be selected, as long as the peak hour falls within the window. The wind generation from that four-hour period in all days of the month is then sorted, and the median value is calculated. The median value is the capacity value of wind for the month. If multiple years of data are available, the process is carried out on the multi-year data set. The results of these calculations are used in operational planning in the power pool.

Portland General Electric (PGE): PGE assumed a 33 percent capacity factor in its 2002 IRP as a placeholder and plans to review additional studies and data as they become available.[17] PGE's IRP calls for 195 MW of wind.[18]

Idaho Power: Idaho Power gives wind a 5 percent capacity credit, based on a 100 MW wind plant's projected output that would occur 70 percent or more of the time between 4 p.m. and 8 p.m. during July, Idaho Power's peak month.[19] Therefore, Idaho Power's method is similar to SPP's by multiplying a subjective statistical number by actual capacity factor values.

Puget Sound Energy (PSE): PSE just released its 2005 IRP that includes a wind integration study as an appendix. Although not specified in the plan, a personal communication with a PSE representative determined that PSE's determination of a capacity credit for wind is the lesser of 20 percent of nameplate capacity, or 2/3 of the capacity factor of a wind project in January, which is PSE's peak month.[20]

Table 1: Wind Capacity Value in the United States

Region/Utility	*Method*	*Note*
CA/CEC	ELCC	Rank bid evaluations for RPS (low 20s)
PJM	Peak period	Jun-Aug HE 3 p.m.–7 p.m., capacity factor using 3-year rolling average (20%, fold in actual data when available)
ERCOT	10%	May change to capacity factor, 4 p.m.–6 p.m., Jul (2.8%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26–34%)
GE/NYSERDA	ELCC	Offshore/onshore (40%/10%)
CO PUC/Xcel	ELCC	PUC decision (30%) and Current Enernex study possible follow-on; Xcel using MAPP approach (10%) in internal work
RMATS	Rule of thumb	20% all sites in RMATS
PacifiCorp	ELCC	Sequential Monte Carlo (20%)
MAPP	Peak period	Monthly 4-hour window, median
PGE		33% (method not stated)
Idaho Power	Peak period	4 p.m.–8 p.m. capacity factor during July (5%)
PSE and Avista	Peak period	PSE will revisit the issue (lesser of 20% or 2/3 Jan C.F.)
SPP	Peak period	Top 10% loads/month; 85th percentile

Table 1 provides results from recent studies, RTO policies, and state regulatory actions to illustrate the range of capacity values found to apply to wind. Most approaches use either ELCC or a time-period basis to calculate wind capacity factor.

IV. The 95 Percent Fallacy: Using *X* Percentile to Calculate Capacity Credit

New gas plants are capable of achieving low forced outage rates—high levels of reliability. Because gas plants have often been the generator technology of choice in recent years, it can be tempting to use this gas plant characteristic in an attempt to estimate the capacity value of an intermittent generator such as wind. To carry out this approach, one collects wind generation over the relevant high-load period (for example, the top 10 percent of load hours). The next step is to calculate the 95th percentile of wind generation—the level of wind generation that is achieved 95 percent of the time during these load hours. A variation of this approach that we have encountered is to then feed this 95th percentile generation into a reliability model to calculate the ELCC of the wind plant. In both of

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these variations, the method *only* values capacity levels that are exceeded 95 percent of the time. All other capacity levels are assigned a value of zero. Although using different percentage levels, this is equivalent to what SPP and Idaho Power did in estimating the capacity value of wind.

The use of a percentile arbitrarily discounts reliability contributions that are achieved at levels below the percentile value. These approaches are based on the fallacious use of probability theory, and they ignore the statistical independence of outages and the fact that system reliability can be achieved at a very high level (such as 1-day-in-10-years LOLE) even though every unit in the system is somewhat unreliable. Furthermore, when applied to wind, this can result in the acquisition of more reserve capacity than is needed, raising costs unnecessarily.

To illustrate, we set up a series of reliability cases using hourly load data from the California ISO. Instead of using the existing generator fleet, a hypothetical generator mix was developed that consists of 95 500 MW units, each with a forced outage rate of 9 percent. The base case also included 54 100 MW units, each with a forced outage rate of 10 percent. This mix of generation achieved a 1-day-in-10-year reliability level. To illustrate the impact of less-reliable plants, the forced outage rates on the 100 MW units was increased in steps of 10 percent up to 90 percent. And just for fun, we also included a case with all the 100 MW units and a 95 percent forced outage rate. **Figure 2** shows that the 1-day-in-10-year reliability target can be achieved even with generators with the 95 percent forced outage rate. The point of this exercise is not to argue for unreliable generators. The point is to show that even unreliable units can contribute to a reliable system, although it would take many of these generators to do so.

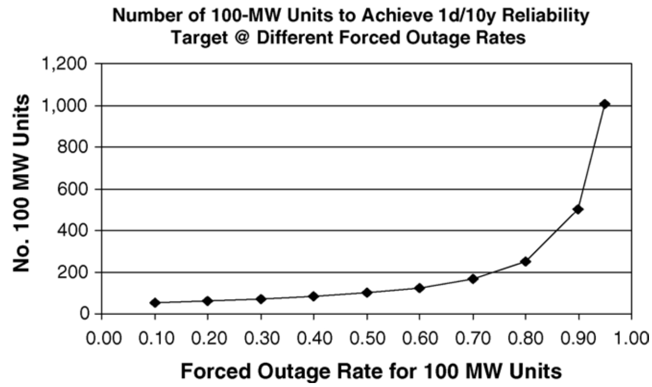

Figure 2: One-Day-in-10-Years can be Achieved with Unreliable Generators

V. Summary

A capacity-based metric is useful in several alternative contexts, from determining resource adequacy to financial markets for capacity. Capacity from a generator at some time in the future is not guaranteed. Because all generators are subject to outages, even during critical times, a probabilistic approach to calculating capacity value is appropriate. This is especially true for intermittent resources such as wind power plants. Because of the stochastic nature of the wind, and therefore wind energy, a method that can explicitly quantify the risks associated with this resource is critical. Standard power system reliability theory exists that can be used for this purpose.

When a reliability-based approach is used to calculate the capacity credit of wind power plants, risk is explicitly embodied in the calculation. The ELCC method is rigorous, data-driven, and can finely distinguish among generators that have different impacts on system reliability. However, the method requires datasets that are not always available and is influenced by many system characteristics. For these reasons and others, simplified methods have been developed. These methods are sometimes based on wind generation during a time period that corresponds to high system risk hours. In other cases, methods can approximate the system LOLP curve so that high-risk hours receive more weight than other hours. We favor experimentation with such methods but suggest

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that it would be helpful to benchmark simple methods against ELCC. This will help eliminate the sometimes-arbitrary assumptions that can be introduced by some simple calculations we have encountered.

Interannual variability of wind generation is an important issue, and it can have an effect on any capacity metric. We recommend that multiple years of data be used in capacity value calculations. If that is not possible, we think that some approaches covered in this article can be useful.

Going forward, we expect that the capacity value of wind generating plants will continue to be a topic that receives significant attention. As more experience with the capacity value of wind energy is gained, we encourage open analysis and reporting of the findings.■

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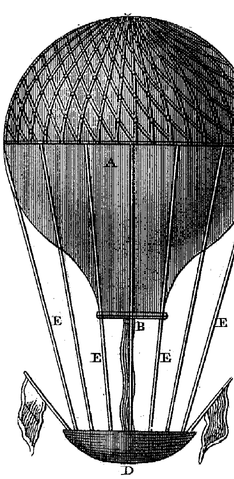

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