ROLE OF HYDROSTATIC TESTING
IN PIPELINE INTEGRITY ASSESSMENT

by

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INTRODUCTION

Hydrostatic testing is universally known and accepted as a means of demonstrating the fitness of a pressurized component for service[1,2]. After a test, a pipeline or pressure vessel can be expected to safely contain its intended operating pressure. The confidence level that a pipeline or pressure vessel is fit for safe service increases as the ratio of test pressure to operating pressure increases. This highly beneficial aspect of hydrostatic testing applies not only to a new component to be placed in service for the first time. A similar benefit accrues to an in-service component if that component is taken out of service after a period of time and subjected to a hydrostatic test. A "revalidation" test of the latter type assures either that no significant time-dependent deterioration of the component has taken place or that any segment that has been significantly degraded will be revealed and eliminated.

There are limitations to the use of hydrostatic testing to revalidate integrity. Some are economic, some are technical, and some are both economic and technical in nature. First, taking a segment of a pipeline out of service means loss of service for the period of the test. Some operators may have this option; others may not. Certainly an operator cannot afford to cut off customers without providing alternative supplies. For single-line systems, this may not be possible. Technical limitations include the fact that a test is a go/no-go device. A test reveals weaknesses by causing ruptures or leaks; it does not indicate, for example, other areas where active corrosion may be taking place. A limitation that has both technical and economic implications is that a level of test pressure to operating pressure sufficient to generate high confidence may result in numerous test breaks or leaks. Repeated test failures may actually

reduce confidence in the final margin of safety[2]*demonstrated by the test, and such failures will certainly add significantly to the cost of the test and the time out of service. With careful weighing of the benefits and limitations nevertheless, some pipeline operators will be able to use hydrostatic testing as a means of integrity assessment. The objective of this presentation is to show how such testing might be used to assess the integrity of existing gas pipelines.

CALCULATING THE TECHICAL BENEFITS

Implications of Defects in Pipelines

The purpose of hydrostatic testing a pipeline is to either eliminate any defect that might threaten its ability to sustain its maximum operating pressure or to show that none exists. A key word here is pressure. Hydrostatic testing consists of raising the pressure level above the operating pressure to see whether or not any defects with failure pressures above the operating pressure exist. If defects fail and are eliminated or if no failure occurs because no such defect exists, a safe margin of pressure above the operating pressure is demonstrated. Defects adversely affect the pressure-carrying capacity because they take away stress-carrying material. Figure 1 illustrates the significant parameters of a longitudinally oriented defect that extends part of the way through the wall thickness. Longitudinal extent, depth-to-thickness ratio, and the strength of the material determine the effect of the defect on hoop stress carrying capacity. Hoop stress is directly related to pressure by the "Barlow" formula, the design formula, the design formula for pipelines. The design formula is

$$t = \frac{PD}{2S}$$

where

        t   is the required wall thickness, inch

        D   is the outside diameter of the pipe, inches

        S   is the allowable hoop stress

               For a Class-1 design $S = 0.72$ SMYS

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* The implications of defect growth during hydrostatic testing are thoroughly discussed in Reference 2. Such considerations are beyond the scope of this paper, but it can be said that these effects are not sufficiently significant to negate the value of hydrostatic testing.

For a Class-2 design   S = 0.60 SMYS

For a Class-3 design   S = 0.50 SMYS
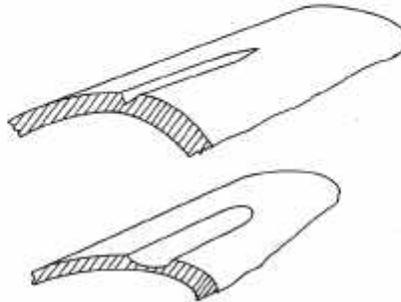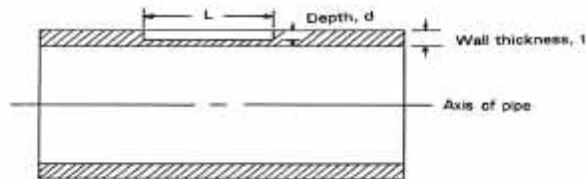
For a Class-4 design   S = 0.40 SMYS,

Figure 1. Surface Flaw Parameters

So if a defect with length L and uniform depth d exists, it takes away material counted on to sustain the design pressure safely. In fact, the stress level in the reduced thickness area is increased and the more metal that is missing the greater the stress in the net thickness becomes. It is not hard to conceive that if the defect becomes large enough, the stress level in the remaining ligament of wall thickness will reach the ultimate tensile strength of the material, and it will fail. Note that we are talking about hoop stress from pressure. Some amount of longitudinal stress is created in a pipeline by internal pressure, but the longitudinal stress created by pressure is never more than one half of the hoop stress. For that reason, hydrostatic testing is not considered to be particularly useful for assessing pipeline integrity from the standpoint of circumferentially oriented defects. Since pipeline integrity is much more likely to be affected by longitudinally oriented defects than by circumferentially oriented defects, hydrostatic testing is one of the best ways to demonstrate the integrity of a pipeline.

Failure Pressure Versus Defect Size

The effects of various sizes of defects on the pressure-carrying capacity of a particular pipeline are shown in Figure 2. This pipeline is comprised of 24-inch-outside-diameter by 0.250-inch-wall-thickness Grade X52 line pipe. Figure 2 presents nine different curves representing the effects of longitudinally oriented, rectangular defects of nine depth-to-thickness ratios as a function of length. All nine curves converge on a maximum value of failure pressure as the lengths of the nine defects approach zero. At zero length there is no defect, and the pipe fails at its ultimate pressure-carrying capacity (i.e., its unflawed burst pressure). In the model[*] used to generate these curves, the ultimate pressure-carrying capacity is assumed to correspond to a hoop stress level of SMYS + 10,000 psi. Therefore, for this pipe material,

$$P_{burst} = 2 \, (SMYS + 10,000)t/D$$
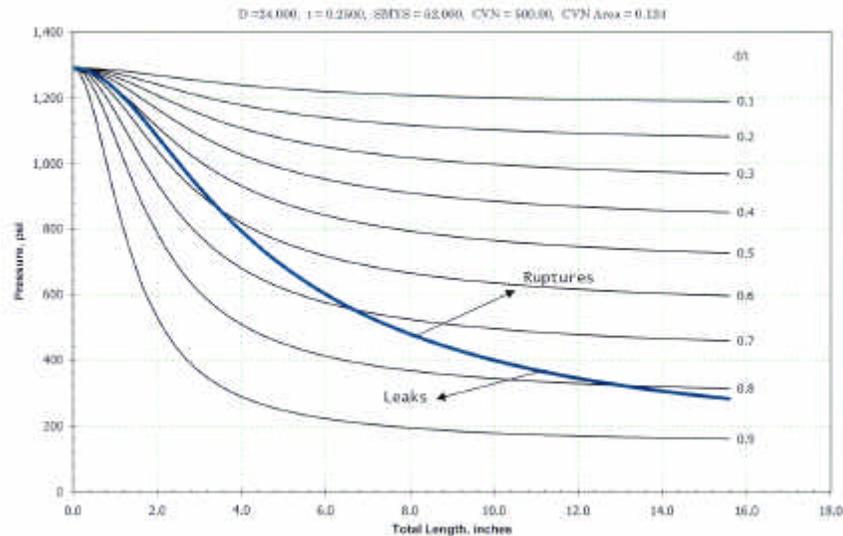$$= 2 \, (62,000)(0.250)/24$$
$$= 1,292 \text{ psig.}$$

Figure 2. Strength Dependent Behavior

One can see that the effects of the defects vary with both length and depth. Deep defects (d/t = 0.7, 0.8, and 0.9 for example) have dramatic effects on pressure-carrying capacity if they are relatively long. In fact, one can see that for very long defects (more than 16 inches in this

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[*] The particular model is described in Reference 1 and thoroughly validated in References 3 and 4. It was generated under A.G.A. sponsorship in the late 1960s, and it is the basis of the ASME B31G and RSTRENG models.

material), length has little influence and the failure pressure is mainly a function of d/t (depth-to-thickness ratio). This aspect of rectangular (i.e., uniform depth) defect behavior could be predicted without a model. Note that the d/t = 0.1 curve levels out at a pressure level just under 1,200 psig corresponding to a 10-percent reduction in burst pressure. Similarly, the d/t = 0.2 curve levels out at a pressure level of around 1,070 psig corresponding to nearly a 20-percent reduction in burst pressure. One could predict this from the Barlow formula. If you remove 10 percent of the wall thickness, you increase the hoop stress in the net thickness by 10 percent. If you remove 20 percent of the wall thickness, you increase the hoop stress in the net thickness by 20 percent, and so on. Thus, the model in this case meets common-sense expectations.

This embodiment of the model is accurate for blunt defects in ductile materials. It would tend to overpredict failure stress levels for crack-like defects in "notch-sensitive" materials where significant crack growth would begin to take place at net thickness stress levels below the ultimate tensile strength of the material. For example, Figure 3 shows the effects of crack-like defects in a material with a typical 1960s level of notch toughness. In Figure 3, the nine d/t curves no longer predict minimum values that tend to agree with the Barlow formula. In this material, cracks will begin to grow and grow to failure at applied stress levels below those predictable by Barlow formula.
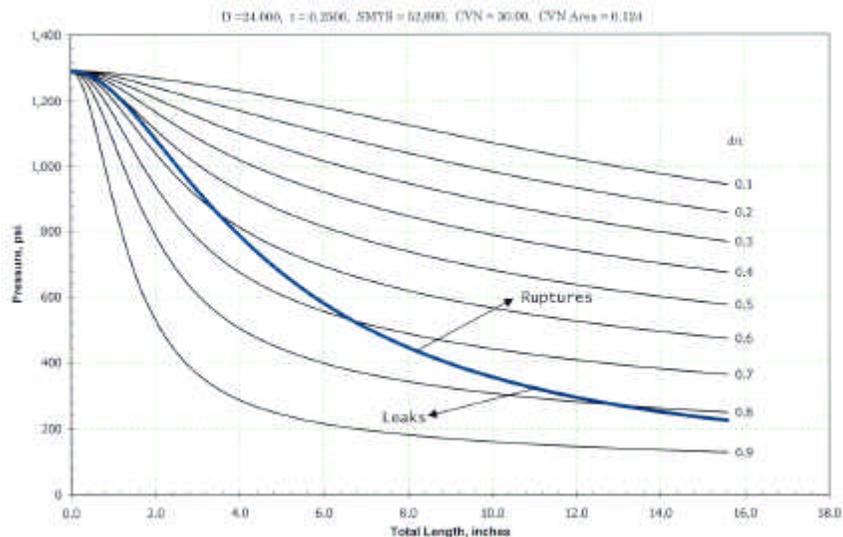

Figure 3. Toughness Dependent Behavior

A final important aspect of either Figure 2 or Figure 3 is the leak-rupture dividing line. While a thorough explanation of how this line is determined is provided in Reference 1, the main thing that it means to this presentation can be explained as follows. Defects (that is length and depth combinations) that lie on or above and to the right of the dividing line will fail as ruptures with rapid axial crack propagation. Defects that lie below and to the left of the dividing line will fail as leaks with no axial crack propagation.

Defect Sizes That Cause Service Failures

Let us now consider Figure 4, which is nearly the same as Figure 3, but contains a red horizontal line corresponding to a 350-psig maximum operating pressure level. From Figure 4 we can discern that a defect that is 90 percent through the wall (d/t = 0.9) will fail at the 350-psig operating pressure if it is about 3.2 inches long, or that an 8-inch-long defect will fail at 350 psig if it is about 79 percent through the wall. Both defects would fail as leaks because sizes put them on the lower side of the leak-rupture line. In contrast, a defect 16 inches in length would fail at 350 psig if it was 70 percent through the wall, but it would fail as a rupture.
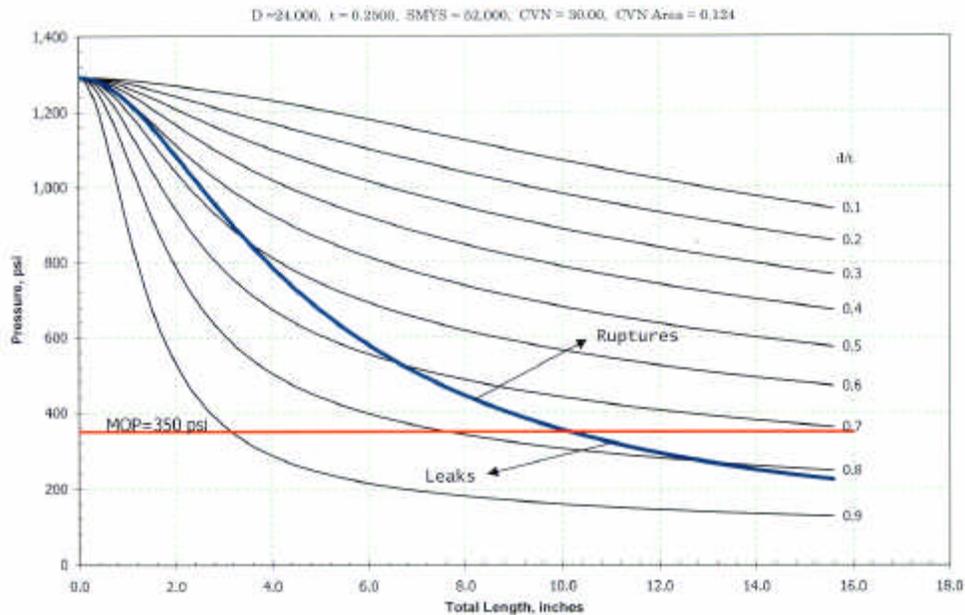

Figure 4. Defect Sizes which Fail at 350 psi

Now let us consider Figure 5, which shows the same material, but one that is operated at a maximum operating pressure of 780 psig (corresponding to 72 percent of SMYS). In this case, we see that the defects that will cause failure at the maximum operating pressure of 780 psig are smaller than those that cause failures at 350 psig. For example, a 3.2-inch-long defect only has to be about 68 percent through the wall to cause a failure at 780 psig compared to the 90-percent through-wall defect required to cause failure at 350 psig. Similarly, the 8-inch-long defect only has to be about 46 percent through to cause failure instead of 79 percent through, and the 16-inch-long defect only has to be 28 percent through to cause failure instead of 70 percent through. Note also that both the 8 and the 16-inch-long defects will fail as ruptures at 780 psig whereas an 8-inch-long defect could only fail as a leak at 350 psig.
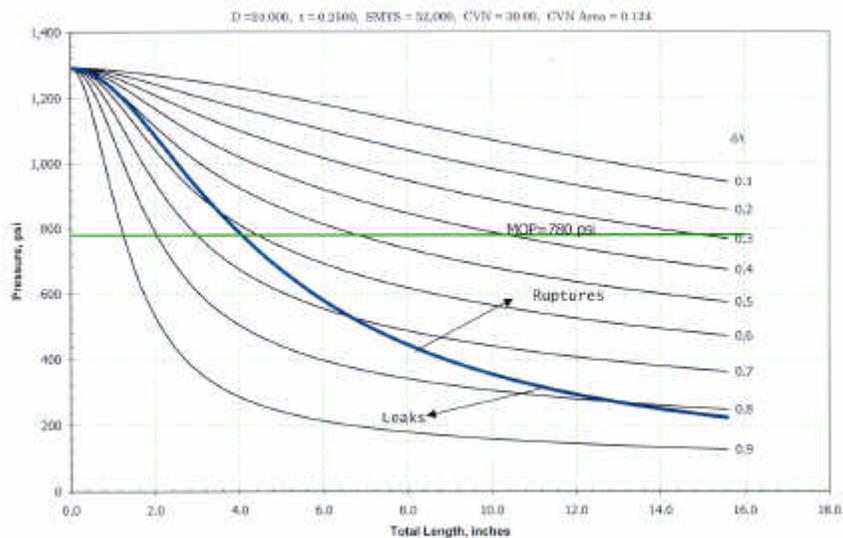

Figure 5. Defect Size which Fail at 780 psi

What this shows is that successively smaller defects are tolerable as the pressure level is increased. The good news is that this is the explanation for the usefulness of hydrostatic testing to a level in excess of the operating pressure as a means of integrity assessment.

Significance of a Hydrostatic Test

For purposes of this section of the presentation, let us consider Figure 6. In this case, Figure 6 is based on Figure 2, the blunt-defect relationship where toughness was not a factor.

The reason for using this embodiment of the model is that it applies to defects caused by corrosion, a relevant type of defect for integrity assessments.
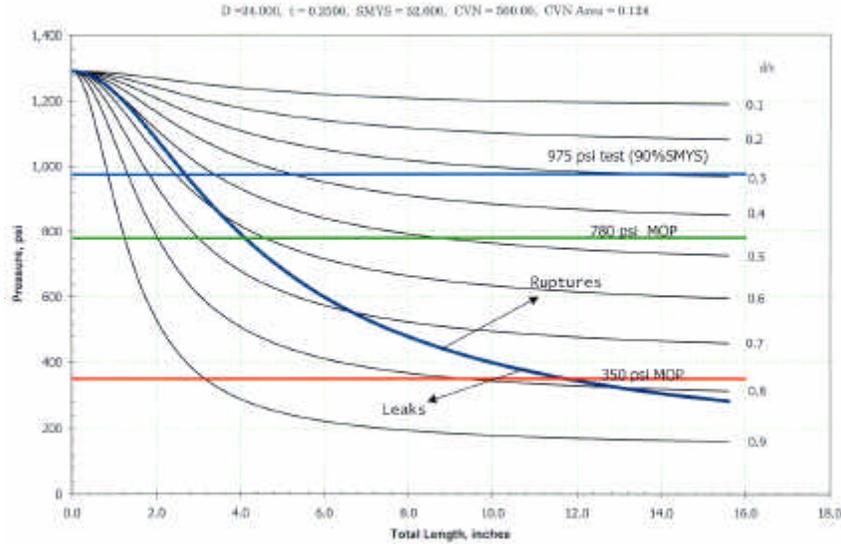

Figure 6. Effects of Hydrostatic Test

On Figure 6, the red horizontal line represents the pipeline operating at 350-psig maximum operating pressure, the green horizontal line represents the pipeline operating at 780 psig, and the blue horizontal line represents a hydrostatic test to 975 psig (90 percent of SMYS). If one applies a hydrostatic test pressure of 975 psig to a pipeline of this size and material, the blue line illustrates the lower bound for the sizes of defects that could remain after such a test. In other words, after such a test a defect with a length of 3.2 inches can be no deeper than 51 percent of the wall thickness, a defect with a length of 8 inches can be no deeper than 34 percent of the wall thickness, and a defect with a length of 16 inches can be no deeper than 29 percent of the wall thickness. Table 1 presents comparisons of the sizes of defects that will fail at the three different pressure levels: 975 psig, 780 psig, and 350 psig.

Table 1. Comparisons of Critical Defect Sizes at Three Pressure Levels for 24-Inch OD by 0.250-Inch X52 Pipe

Pressure Level, psig	Defect Size Parameters	
	L, inches	d/t
975	3.2	0.51
780	3.2	0.68

Pressure Level, psig	Defect Size Parameters	
	L, inches	d/t
350	3.2	0.90
975	8.0	0.34
780	8.0	0.51
350	8.0	0.81
975	16.0	0.29
780	16.0	0.45
350	16.0	0.77

It is obvious from these values that immediately after a test to 975 psig, the pipeline is serviceable at either the 350-psig or 780-psig operating pressure.

**Benefits of a Given Test Pressure with
Respect to a Given Operating Pressure**

What may not be obvious immediately from Figure 6 or Table 1 is that a test to 975 psig is more beneficial for the pipeline if it is operated at 350 psig than it is if the pipeline is operated at 780 psig. The larger benefit for the lower operating pressure is easy to demonstrate. Let us assume that the pipeline is corroding at a rate of 10 mils (10 thousands of an inch) per year. Referring to Figure 7, one can discern the sizes of defects expected to fail at or barely survive a pressure of 975 psig stated in Table 1. One can utilize the vertical black arrows to see what might happen if these three corroded areas barely survived the test and continued to grow at 10 mils per year. The 3.2-inch-long defect, which could survive the test to 975 psi if its d/t ratio was less than 0.51, would be expected to fail at a pressure level of 780 psi when its d/t ratio reached 0.68 or at a pressure level of 350 psi when its d/t ratio reached 0.90. Similarly, the 8-inch-long defect (which barely survives the test if its d/t ratio is 0.34) would be expected to fail at a pressure of 780 psig when its d/t ratio reached 0.51 or at a pressure level of 350 psig when its d/t ratio reached 0.81. Table 2 presents these data and the implications for all three defects.
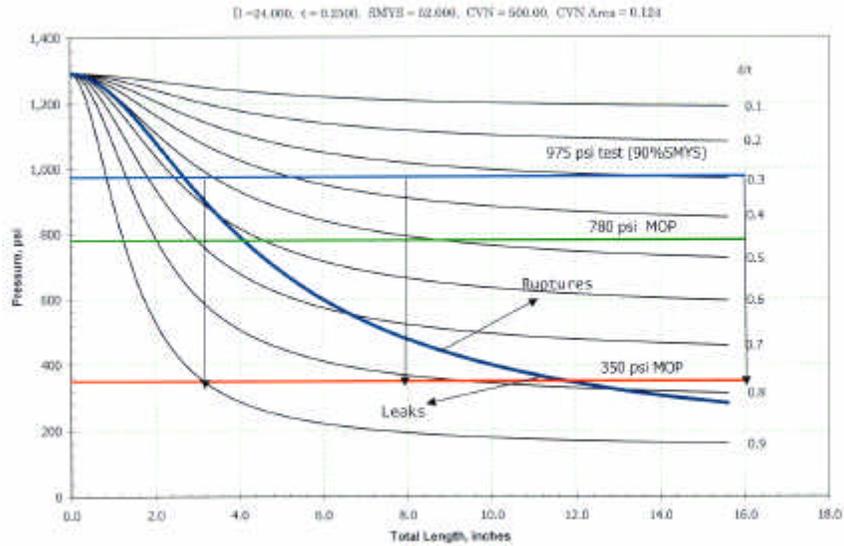
Figure 7. Effects of Defect Growth After Hydrostatic Test

Table 2. Times to Failure After the Test at a Corrosion Rate of 10 Mils Per Year

Maximum Operating Pressure	Amount of Growth to Cause Failure		Number of Years to Failure at $d/(10 \times 10^{-3})$, years
	Change in d/t	Change in d, inch (t=0.250)	
780	0.17 (L=3.2 inches)	0.0425	4.3
	0.17 (L=8 inches)	0.0425	4.3
	0.16 (L-16 inches)	0.0400	4.3
350	0.39 (L=3.2 inches)	0.0975	9.8
	0.47 (L=8 inches)	0.118	11.8
	0.48 (L=16 inches)	0.12	12.0

Clearly, the test to 975 psig delivers a greater benefit for the pipeline operating at 350 psig than it does for the pipeline operating at 780 psig. The operator of the780-psig pipeline would have to conduct retests 2-1/2 to 3 times as frequently as the operator of the 350-psig pipeline to get the same level of integrity assurance. The operator of the 350-psig pipeline needs to note, however, that the tests must be carried out at 975 psig (90 percent of SMYS) for that benefit to accrue. If, for example, the operator of the 350-psig pipeline conducted the test at a pressure of only 780

psig instead of 975 psig, the degree of integrity assurance would be less (i.e., retests would have to be conducted more frequently to maintain a specific level of confidence). This fact can be discerned from the data of Table 1 by noting that the changes in d/t ratios between failure at 780 psig and failure at 350 psig would result in the margin of safety being used up in 5.5 years for the 3.2-inch-long defect, 7.5 years for the 8-inch-long defect, and 8 years for the 16-inch-long defect at a corrosion rate of 10 mpy. It is also noted that our examples apply to 0.250-inch-wall-thickness pipe.; At a fixed rate of corrosion, the benefits of testing will be greater for thicker pipe.

SUMMARY AND CONCLUSIONS

This presentation has shown the technological benefits of hydrostatic testing as a means of integrity assurance for pipelines. A well-proven model has been used to show that those benefits are quantifiable. References 1 and 2 are available for those who wish to review the detailed findings of 20 years of A.G.A.-sponsored work on the subject. A more concise and more recent summary is available in Reference 5. The economic issues of hydrostatic testing are extremely important and will determine whether or not hydrostatic testing can be used on any given pipeline. For those operators who will be able to use hydrostatic testing, this presentation offers some useful guidelines to help the operator optimize confidence in the test as a means of integrity assurance.

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